2020 Integrated System Plan

July 2020

For the National Electricity Market

Important notice

PURPOSE

AEMO publishes this 2020 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 broader functions under the National Electricity Rules to maintain and improve power system security. In addition, AEMO has had regard to the National Electricity Amendment (Integrated System Planning) Rule 2020 which commenced on 1 July 2020 during the development of the 2020 ISP.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2020	Initial release

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Appendices

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BESS	Battery energy storage system
BOM	Bureau of Meteorology
BOTN	Battery of the Nation
CCGT	Combined-cycle gas turbine
DER	Distributed energy resources
DNSP	Distribution network service provider
DSP	Demand side participation
ENA	Energy Networks Australia
ESB	Energy Security Board
ESCI	Electricity Sector Climate Information
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
FOS	Frequency operating standard
GPG	Gas-powered generation
GW	Gigawatt/s
GWh	Gigawatt hour/s
GWs	Gigawatt second/s
HILP	High impact low probability
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
Hz	Hertz
IBR	Inverter-based resources
IRM	Interim Reliability Measure
kV	Kilovolt/s
LCOE	Levelized cost of electricity
LNG	Liquified natural gas
LOR	Lack of Reserve
MDI	Market Design Initiative
MLF	Marginal loss factor
MW	Megawatt/s
MWh	Megawatt hour/s
WMs	Megawatt second/s
NEM	National Electricity Market
NPV	Net present value
OCGT	Open-cycle gas turbine
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PHES	Pumped hydro energy storage
PJ	Petajoules
PSCR	Project Specification Consultation Report
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable energy zone
RIS	Renewable Integration Study
RIT-T	Regulatory Investment Test for Transmission
ROCOF	Rate of change of frequency
RRO	Retailer Reliability Obligation
SPS	Special Protection Scheme
TNSP	Transmission network service provider
TRET	Tasmanian Renewable Energy Target
VCR	Value of Customer Reliability
VNI	Victoria – New South Wales Interconnector
VPP	Virtual power plant
VRE	Variable renewable energy
VRET	Victorian Renewable Energy Target

PREFACE

The integrated system plan for Australia's future energy systems

The first Integrated System Plan (ISP) was prepared by AEMO and endorsed by the COAG Energy Council in 2018. It has since guided governments, industry and consumers on investments needed for an affordable, secure and reliable energy future, while meeting prescribed emissions trajectories, and triggered the processes for actionable ISP projects.

With the ISP to be updated every two years, AEMO is pleased to present the 2020 ISP, which responds to the latest technology, economic, policy and system developments.

The ISP identifies investment choices and recommends essential actions to optimise consumer benefits as Australia experiences what is acknowledged to be the world's fastest energy transition. That is, it aims to minimise costs and the risk of events that can adversely impact future power costs and consumer prices, while also maintaining the reliability and security of the power system.

Provided that the transmission investments are timely and kept at an efficient level, the combined supply and network investments proposed in the ISP are expected to deliver $11 billion in net benefits to the National Electricity Market (NEM). As regulated network investments typically have long lead times, the ISP provides clear signposts for decision making as the future unfolds.

In parallel with the ISP, the Energy Security Board (ESB) and market bodies are exploring essential reforms to attract investment and optimise bidding of supply and demand based energy resources.Without reforms that can enable these market-based investments, the ISP benefits will not be realised in full.

The ISP serves its essential national purpose because it draws on constructive and critical input from all parties. AEMO consulted widely over the past 18 months in preparing this ISP, leading to important improvements from both the 2018 ISP and the Draft 2020 ISP, and we appreciate the considered input of all who participated.

We will continue to work hand-in-hand with the industry, government and consumers in making our energy system affordable, secure, reliable and sustainable.

Audrey Zibelman
Chief Executive Officer and Managing Director

A roadmap to guide Australia's energy transition
[Executive summary]

The 2020 ISP is an actionable roadmap for eastern Australia's power system to optimise consumer benefits through a transition period of great complexity and uncertainty. It does so by drawing on extensive stakeholder engagement as well as internal and external industry and power system expertise.

A. The ISP is a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy through a complex and comprehensive range of plausible energy futures. It identifies the optimal development path for the National Electricity Market (NEM), consisting of ISP projects and development opportunities, as well as necessary regulatory and market reforms.

B. AEMO developed the ISP using cost-benefit analysis, least-regret scenario modelling and detailed engineering analysis, covering five scenarios, four discrete market event sensitivities and two additional sensitivities with materially different inputs. The scenarios, sensitivities and assumptions have been developed in close consultation with a broad range of energy stakeholders.

C. This analysis identified the least system cost investments needed for Australia's future energy system. These are distributed energy resources (DER)[1], variable renewable energy (VRE)[2], supporting dispatchable resources and power system services. Significant market and regulatory reforms will be needed to bring the right resources into the system in a timely fashion.

D. The analysis also identified targeted augmentations of the NEM transmission grid, and considered sets of investments that together with the non-grid developments could be considered candidate development paths for the ISP.

E. The ISP sets out the optimal development path needed for Australia's energy system, with decision signposts to deliver the affordability, security, reliability and emissions outcome for consumers through the energy transition.

F. When implemented, these investments will create a modern and efficient energy system that delivers $11 billion in net market benefits, and meets the system's reliability and security needs through its transition, while also satisfying existing competition, affordability and emission policies.

[1] Including rooftop PV, batteries, and other resources at the customer level

[2] Including solar, wind, and other variable renewable energy resources at the utility level

A A dynamic, whole-of-system roadmap is needed

The NEM is an intricate system of systems, which includes regulatory, market, policy and commercial components. At its centre is the power system, which is an inherently complex machine of continental scale. This system is now experiencing the biggest and fastest transformational change in the world[3] since its inception over 100 years ago.

The ISP is a whole-of-system plan that efficiently achieves power system needs through that transformational change, in the long-term interests of the consumers of electricity[4]. It serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision makers and consumers.

- **Its scope is the whole NEM power system.** As a rigorous whole-of-system plan, the ISP is a far more comprehensive and richer analysis than other comparable modelling exercises for Australia's energy future. It takes into account not only the capital and fuel costs of generation but also future network developments and deployment of DER. It includes a degree of sector coupling with the transport and gas sectors. It also takes the first steps towards including insights on the role of hydrogen[5]. It incorporates innovations in consumer-owned DER, virtual power plants (VPPs), large-scale generation, energy storage, and power-system services. Finally, it ensures the physical limitations and constraints of Australia's energy system are accurately represented.
- **Its planning horizon is the next two decades, to 2040.** As its planning horizon is at least 20 years, the ISP must provide a least-regret, dynamic, resilient and transparent roadmap for the NEM through Australia's energy transition, as well as increase system resilience to better deal with future challenges.
- **Its guiding objective is to meet power system needs while optimising net market benefits**. These system needs include enabling consumer affordability and maintaining system reliability and security while meeting government emissions and renewable energy policies. If these objectives are met at low long-term system cost – measured by whole-of-system cost-benefit analysis and incorporating construction, operation and compliance costs – it will optimise net market benefits in the long-term interests of consumers.
- **It must recognise the risks to consumers of investments made in times where there are multiple uncertainties.** Change is certain in the economic, trade, security, policy and technology environments in which the NEM operates. Yet energy investments must be made, as Australian consumers rely on them for their economic and physical wellbeing. If essential investments are delayed or aborted, domestic and industrial consumers will face increased costs and risks. On the other hand, if planning and investment occurs in an uncoordinated way or is done inefficiently, customers and investors will experience the risk and cost of excess investment. Selecting an optimal development path must therefore take into account consumer benefits, the essential nature of electricity as a service and prudent risk management.
- **The ISP must therefore be a transparent, dynamic roadmap.** The ISP identifies the energy resources the market needs to deliver in each possible scenario to meet consumer needs. It sets out the actionable and future ISP projects, which can be network or non-network solutions, that allow the combination of energy resources to work optimally and efficiently together. It combines the ISP projects

[3] The Australian energy system is acknowledged to be undergoing the world's fastest transformation: Blakers et al., (2019) "Pathway to 100% Renewable Electricity", *IEEE Journal of Photovoltaics*, Vol. 9, No 6.

[4] The ISP is governed by Clause 5.22 of the National Electricity Rules (NER) – the ISP Rules. Obligations set out in Part A are set by those Rules.

[5] See Appendix 10

into the NEM's optimal development path, and so triggers the processes for regulatory investment tests for transmission (RIT-Ts). It then goes further to recommend signposts and decision points to keep the power system resilient as economic, physical and policy environments change over the time horizon.

B Deep consultation and modelling for the ISP

The ISP continues to project a profound transition to a NEM of diverse renewable, conventional and distributed generation, supported by energy storage and network solutions. AEMO uses scenario modelling and cost-benefit analysis to determine the most efficient ways to meet power system needs through that transition, in the long-term interests of consumers. The approach aligns with the new ISP Rules and the intent of the Australian Energy Regulator's (AER's) proposed *Cost-Benefit Analysis Guidelines* for the ISP and regulatory investment tests[6].

The elements of the scenario modelling included:

- **Consultation on ISP assumptions, scenarios and sensitivities that span all plausible operating environments.** AEMO consulted extensively with industry, academia, government, developers and consumer representatives, culminating in our *Forecasting and Planning Scenarios, Inputs and Assumptions Report* in August 2019. AEMO has since updated multiple inputs and assumptions, drawing on feedback received on the Draft 2020 ISP and further analysis.
- **Five scenarios to trace different speeds of transition**. The Central scenario is determined by market forces and current federal and state government policies. The other scenarios vary in the pace of the transition – a Slow Change scenario with slower economic growth and emission reductions, a High DER scenario with more rapid consumer adoption of DER, a Fast Change scenario with greater investment in grid-scale technology, and a Step Change scenario where both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation.
- **Four sensitivities to vary the timing of key market events.** These considered the earlier retirement of existing generators, Snowy 2.0 delays, a closure of large industrial load in Victoria and Tasmania, and the early development of VRE in the Central-West Orana Renewable Energy Zone (REZ).
- **Two new sensitivities to test changes in inputs** that could materially alter the optimal development path: legislation of a Renewable Energy Target in Tasmania, and updated demand forecasts including the potential impacts of COVID-19 and current trends in PV sales on demand**.**

C ISP development opportunities for an optimal energy system

The ISP modelling confirms that the least-cost and least-regret transition of the NEM is from a system dominated by centralised coal-fired generation to a *highly diverse* portfolio of behind-the-meter and grid-scale renewable energy resources that are supported by dispatchable firming resources and enhanced grid and service capabilities, to ensure the power system remains physically secure.

ISP development opportunities are projects that do not involve a transmission asset or non-network option and include distribution assets, generation, storage projects, or demand side developments that are consistent with the efficient development of the power system.

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[6] Consultation Draft AER Cost benefit analysis guidelines May 2020: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable. AEMO looks forward to working with the AER to refine the guidelines where appropriate and as informed by the real life experience of delivering this ISP

While the ISP Rules pave the way for actionable transmission projects through the RIT-T process, there is no similar regulatory mandate for other resources, such as generation and storage. Rather the ISP offers a signal to inform the decisions of private developers. Market design is therefore crucial for both regulated and private investment to deliver the least cost outcome for consumers.

By 2040 the ISP development opportunities are those which support the ISP findings that:

1. **Distributed energy generation capacity is expected to double or even triple.** Residential, industrial and commercial consumers are expected to continue to invest heavily in distributed PV, with increasing interest in battery storage and load management. Depending on the scenario and subject to technical requirements, the AEMO modelling projects DER could provide 13% to 22% of total underlying annual NEM energy consumption[7] by 2040. AEMO is investigating how to maximise the amount of DER that allows consumers to benefit from their investment and the power system to remain secure. It will require dedicated management practices and protocols backed by requisite distribution network investments and changes to rules, regulations and standards; capabilities that allow DER installations to maximise their contribution to the reliability, security and resilience of the power system; and operational management systems to integrate load management. Without urgent and well targeted reforms, the high levels of DER projected in this ISP would not be achievable, and limits may have to be imposed on DER instead, which would be a sub-optimal outcome for Australia.
2. **Over 26 GW of new grid-scale renewables is needed** in all but the Slow Change scenario. This is to replace the approximately 15 GW or 63% of Australia's coal-fired generation that will reach the end of its technical life and so likely retire by 2040. More renewables are required to replace conventional generators because of their naturally lower capacity factor, which has been fully accounted for in this technical and economic analysis. To ensure a gradual, orderly transition, there must be sufficient new generation in place before each major plant exits. Allowing for the strong growth in DER, Australia will still need an additional 26 to 50 GW of new VRE, depending on the scenario, much of it built in REZs. In the Slow Change scenario, only 8 GW would be needed by 2040.
3. **6-19 GW of new dispatchable resources are needed in support.** To firm up the inherently variable nature of distributed and large-scale renewable generation, we will need new flexible, dispatchable resources: utility-scale pumped hydro, large-scale battery energy storage systems, distributed batteries, VPP and other demand side participation (DSP). New flexible gas generators could play a greater role if gas prices remained low at $4 to 6 per GJ over the outlook period. To secure the benefits of all dispatchable resources, market reforms currently being pursued through the ESB's post 2025 market design process should be continued at pace, otherwise necessary resources may not be delivered on time and the system will have to rely on other mechanisms, such as transmission investment. Market design needs to reward the increasing value of flexibility and dispatchability in complementing and firming variable generation, and in providing the other system security services currently provided by the existing generators, which are scheduled to retire.
4. **Power system services are critical to the secure operation of the power system.** The active management of power system services will continue to grow in importance for voltage control and system strength, frequency control and inertia, ramping and dispatchability.

[7] Total annual underlying NEM energy consumption, including rooftop PV, and PVNSG (commercial-scale PV, behind-the-meter and <30 MW per installation). The level of instantaneous uncontrolled power that will need to be operationally managed at times of DER peak export will be much higher.

The NEM will draw on a technological mix that may diversify even further as other technologies mature and become commercially competitive to current generation. This diverse portfolio will cost less than replacing the exiting generators with new thermal generation to deliver the energy and peak capacity needed, and simultaneously reduce emissions significantly.

D Network investments for an optimal energy system

The transmission grid itself requires targeted augmentation to support the change in generation mix. As long as augmentation costs are kept to an efficient level, strategically placed interconnectors and REZs, coupled with energy storage, will be the most cost-effective way to add capacity and balance variable resources across the whole NEM. Without adequate investment in transmission infrastructure, new VRE will be struggling to connect. This could in turn lead to the private sector under-investing in the new generation capacity needed ahead of the planned or unplanned retirement of existing generators.

- **Targeted augmentation to balance resources and unlock REZs**. From a large range of possible options, the ISP's economic and power system modelling has selected 18 projects that are commercially and technically feasible, and would meet the system's physical requirements (listed below).
- **Candidate development paths that deliver power system requirements and economic benefits.** Using economic and power system modelling, AEMO first identified the network augmentations that would meet the system's physical requirements (listed below). It then identified eight possible sets of network augmentations that, together with the development opportunities above, would deliver Australia's energy future (the "candidate development paths"[8]). Five candidates are the least-cost development paths for each of the five core scenarios; and the other three examine if earlier starts to, or staging of, VNI West and Marinus Link would bring benefits over 20 years.
- **Cost-benefit analyses of the candidate development paths.** AEMO modelled the candidates across all scenarios and market event sensitivities, to reveal their net present value (NPV) compared with the counterfactual case of no further transmission investment. The ISP uses the candidate path NPVs in two ways. The first approach is required by the AER's Cost Benefit Assessment (CBA) Guidelines: calculate the weighted-average NPV of the candidates across all scenarios; the weights reflecting the relative likelihood of each scenario occurring. The alternate approach identifies the development path that would cause the least regret if a less ideal scenario unfolds.

In all cases these transmission costs must be minimised as much as possible to ensure consumers pay no more than necessary for their benefits.

E The optimal development path

The optimal development path (see Figure 1) comprises projects to augment the transmission grid as well as the ISP development opportunities set out in Part C. Because the timing of network augmentation and of REZs are so interdependent, both are also set out in Part C.

In selecting the optimal development path, AEMO has considered the outcomes of the two CBA approaches, and also options which may better trade off upfront costs against the possibility of greater

[8] There are differences in the composition and size of the supply side resources, depending on which scenario and which development path apply. The detailed modelling results are set out in the Generation and Transmission Outlook spreadsheets published in conjunction with the ISP.

future costs, in line with consumer appetite for risk. This consideration has affected decision rules for the timing of VNI West and Marinus Link in the optimal development path.

Projects to augment the transmission grid[9]

The ISP has identified four categories of transmission projects – Committed, Actionable, Actionable with decision rules, and Future ISP projects – permitted to be developed by the TNSP through the RIT-T process. They have been carefully selected from a large range of possible options to achieve power system needs through a complex, energy sector transition.

- **Committed ISP projects.** These are critical to address cost, security and reliability issues, and are underway and have already received their regulatory approval.
  - **South Australia system strength remediation,** the installation of four high-inertia synchronous condensers as recommended in the 2018 ISP, and on track to be completed in 2021.
  - **Western Victoria Transmission Network Project,** to support generation from the Western Victoria REZ, including new 220 kV and 500 kV double-circuit lines. The project is on track to be commissioned in two stages, by 2021 and 2025.
  - **QNI Minor,** a minor upgrade of the existing interconnector, adding over 150 MW thermal capacity in both directions, on track to be commissioned in 2021-22.
- **Actionable ISP projects.** These are also critical to address cost, security and reliability issues, and are either already progressing or are to commence immediately after the publication of the 2020 ISP[10]. These projects have not yet completed their regulatory approval process.
  - **VNI Minor**, a minor upgrade to the existing Victoria – New South Wales Interconnector (VNI), which is very close to completing its regulatory approval process, with project completion expected in 2022-23[11].
  - **Project EnergyConnect**, a new 330 kV double-circuit interconnector between South Australia and New South Wales, which is close to completing its regulatory approval process, with project completion expected by 2024-25.
  - **HumeLink**, a 500 kV transmission upgrade to reinforce the New South Wales southern shared network and increase transfer capacity between the Snowy Mountains hydroelectric scheme and the region's demand centres. This project commenced its regulatory approval process earlier this year, with project completion due by 2025-26.
  - **Central-West Orana REZ Transmission Link[12],** involving network augmentations to support the development of the Central-West Orana REZ as defined in the New South Wales Electricity Strategy, and transfer capacity between the Central-West Orana REZ and major load centres of New South Wales. The project completion is due in 2024-25.
- **Actionable ISP projects with decision rules.** These projects are also critical to address cost, security and reliability issues. The decision rules for these projects can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate.

[9] All dates in this section are financial year basis.

[10] Estimated practical completion including any subsequent testing; this project is optimal if it can be delivered earlier

[11] This timing includes necessary inter-regional testing. Earlier delivery would still be optimal.

[12] TransGrid. *Central-West Orana REZ Transmission Link*, available at https://www.transgrid.com.au/centralwestorana

- **VNI West**, a new high voltage alternating current (HVAC) interconnector between Victoria and New South Wales, should be progressed for completion as soon as practicable, which is by 2027-28. Early works for this project should commence as soon as possible for completion in late 2024. This project is currently AEMO's preferred option to maintain system security and reliability in Victoria. It provides a prudent pathway to access sufficent dispatchable capacity to deliver into Victoria and, therefore, avoids the risk associated with earlier than planned exit of a major generator. It will also bring forward additional resilience benefits (for example, in case of an extended BassLink outage, a prolonged wind drought or another extended generator or transmission outage), address the increasingly pressing need to manage minimum demand in Victoria, open up new REZs, and provide Victorian consumers access to Snowy 2.0. To deliver positive net market benefits, project costs have to be below $2.6 billion, based on 2020 ISP assumptions. If there is sufficient certainty that no early generator exit will occur or sufficient new dispatchable resources have been or are expected to be added to the Victorian market, it may make sense to slow the project down for later delivery. VNI West is on the least-cost development path in all scenarios except for Slow Change and High DER.
- **Marinus Link**, two new high voltage direct current (HVDC) cables connecting Victoria and Tasmania, each with 750 MW of transfer capacity and associated AC transmission, should be progressed such that the first cable can be completed as early as 2028-29 (should the Step Change scenario emerge) or no later than 2031-32 (should the Tasmanian Renewable Energy Target [TRET] be legislated or the Fast Change scenario emerge, and the cost recovery be resolved). This requires delivery of early works for both cables to be completed prior to a final investment decision in 2023-24. If by then the Tasmanian Government does not legislate the TRET, or if there is no successful resolution on how the costs of the project will be recovered (from consumers and/or other sources), then the project schedule should be revisited. Marinus Link's first cable is on the least-cost development path in all scenarios except for Slow Change. Marinus Link's second cable should be able to be completed as early as 2031-32, with the decision rules for its completion to be defined in the 2022 ISP.

- **Future ISP projects.** These projects would reduce costs, and enhance system resilience and optionality. They are not yet 'actionable', but are expected to be so in the future and are part of this ISP's optimal development path.
  - **QNI Medium and Large interconnector upgrades**, the staged delivery of upgrades to the Queensland to New South Wales Interconnector (QNI) to share renewable energy, storage, and firming services between the regions after the closure of Eraring or to support government sponsored REZ developments. Each stage is a 500 kV line; the first (QNI Medium) forecast for completion by 2032-33 and the second (QNI Large) by 2035-36. If the New England REZ development is accelerated through New South Wales government policy, then some works for the New South Wales side of these projects may be brought forward as part of the REZ development.
  - **Three additional Queensland augmentations** including upgrading the network from Central to Southern Queensland in the mid-2030s to alleviate constraints; reinforcing the network around Gladstone between 2025 and 2035 to support REZ development; and augmenting the far north Queensland network in the mid-to-late 2030s to enable REZ development and transfer of energy south.

- **Three New South Wales augmentations** including reinforcing the network supplying Sydney, Newcastle and Wollongong from 2026-27 to 2032-33; expanding the network to support the development of a New England REZ, by 2031-2036 (or earlier if the New England REZ development is accelerated through NSW government policy); and expanding the network to support development of a North West NSW REZ by the 2030s, depending on connection interest.
- **Two South Australian augmentations,** including expanding the south-east South Australian network to support additional wind generation connection, and augmenting the mid-north South Australian network to alleviate constraints.

Decision signposts if the environment changes

The NEM is constantly evolving and inevitably forecasts require assumptions to be made that could change over time. A well designed ISP is robust, so these changes don't invalidate the optimal development path, but instead simply signal a pre-determined change in direction. An integrated plan must also reflect the time it takes to design and construct major transmission and incorporate the ability and willingness of market participants to invest in resources that diminish the risk of uncertainty and delay.

To address these complexities, the ISP recommends progressing actions on several fronts to mitigate the risks of insufficient or late investments. This recognises the inherent asymmetry between the significant costs of early investment in large transmission projects, and the even more significant costs and risks of not having adequate resources available when needed to deliver affordable and reliable electricity.

To avoid this risk, the optimal development path includes development of VNI West and Marinus Link as soon as possible, with decision rules that allow for adaptation if circumstances change. The changes noted are not expected to occur before the next (2022) ISP. This dynamic roadmap is essential for the NEM to have both certainty and flexibility, and so meet the cost, security, reliability and emissions expectations of energy consumers through the energy transition.

That roadmap is shown in Figure 2, with potential changes being:

- If the cost of proposed transmission investments exceed the benefits identified by the ISP, alternative developments should be pursued. In any case, every effort should be made to minimise the consumer-borne cost of these regulated assets.
- If we find ourselves in the Slow Change scenario, then AEMO will reassess the need to progress development of Marinus Link and VNI West.
- If there is sufficient market-based dispatchable capacity in Victoria to maintain reliability in the event that brown coal-fired generation in Victoria is retired early or becomes increasingly unreliable, then slow down delivery of VNI West. Similarly, if transmission project costs cannot be retained to an efficient level of $2.6 billion, then the timing and scope of the investment should be reassessed.
- If TRET is legislated, or we find ourselves in the Fast Change scenario, and there is successful resolution as to how the costs of the Marinus Link project will be recovered, then Marinus Link's first cable should be completed by 2031-32.
- If we find ourselves in the Step Change scenario and there is successful resolution as to how the costs of Marinus Link project will be recovered, then accelerate completion of both Marinus Link cables as much as possible.

If the 2022 ISP confirms the value of Marinus Link's second cable, then decision rules for this stage will be established at that time.

ISP development opportunities for renewable energy zones

The 2020 ISP promotes an integrated approach to new generation development, enabled by coordinated network and non-network investments to address system security requirements. The optimal development path in the ISP includes network projects and ISP developments that together will develop the identified REZs.

This ISP has prioritised REZ developments in three overlapping phases that are based on actionable ISP projects in the optimal development path satisfying decision rules and being delivered in accordance with the optimal development path. For actionable ISP projects with decision rules, the REZ developments and phasing assumes that the decision rules are met, and the ISP projects are delivered at the earliest timing.

- **Phase 1:** Development to help meet regional renewable energy targets and other policies, and/or where there is good access to existing network capacity with good system strength, including:
  - *Queensland*: VRE development primarily in Darling Downs and Fitzroy taking advantage of the existing spare network capacity to meet the QRET
  - *New South Wales*: VRE development in Central-West Orana REZ, forming part of the New South Wales Electricity Strategy
  - *Victoria*: The VRE development to help meet VRET in Western Victoria REZ in the mid to late 2020s, supported by the committed Western Victoria Transmission Network Project, and South West Victoria, and Central North Victoria REZ, and
  - *Tasmania*: The development of VRE in Midlands, North East Tasmania and North West to meet the TRET[13].
- **Phase 2**: Renewable generation development to replace energy provided by retiring coal-fired generators and supported by the actionable ISP projects, including:
  - *New South Wales*: VRE development in South West New South Wales REZ supported by the Project EnergyConnect and VNI West (Kerang route)[13], and Wagga Wagga REZ supported by the development of HumeLink, and pumped hydro generation in Tumut REZ, supported by the development of HumeLink.
  - *Victoria*: VRE development in Central North Victoria REZ supported by VNI West (Shepparton route), or Murray REZ supported by VNI West (Kerang route)[13]. VRE development in Western Victoria REZ is also supported by VNI West (either Kerang or Shepparton routes). Development of solar in Murray River REZ near Red Cliffs is supported by Project EnergyConnect.
  - *South Australia*: Development of Riverland REZ enabled by Project EnergyConnect.
  - *Tasmania*: Development of Midlands REZ supported by Marinus Link[13].
- **Phase 3**: Renewable generation development to accompany future ISP projects that are being developed specifically to support them, including:
  - *Queensland*: VRE development in Darling Downs REZ supported by expansions of QNI in 2032-33 and 2035-36. Larger VRE development in Fitzroy REZ and Isaac REZ are supported by the future Gladstone Grid Reinforcement and Central to Southern Queensland transmission project. Developments in Far North Queensland REZ requires upgrades within this REZ to connect

[13] The REZ and timing are based on actionable ISP projects in the optimal development path satisfying decision rules and being delivered in accordance with the optimal development path.

renewable generation. Additional strengthening of the 275 kV network is also required: see Appendix 3 and 5.

  - *New South Wales*: VRE development in North West New South Wales REZ supported by expansions of QNI in 2032-33 and 2035-36. Large developments in New England would require support from an associated future ISP project to augment the transmission system from the REZ to provide stronger access to supply the greater Sydney region.
  - *South Australia*: VRE development in Roxby Downs REZ and Mid-North REZ supported by network upgrades between Davenport and Para. Development of South-east South Australia REZ requires the support of an associated future ISP project to connect generation within the REZ.

F Projected outcomes of the optimal development path

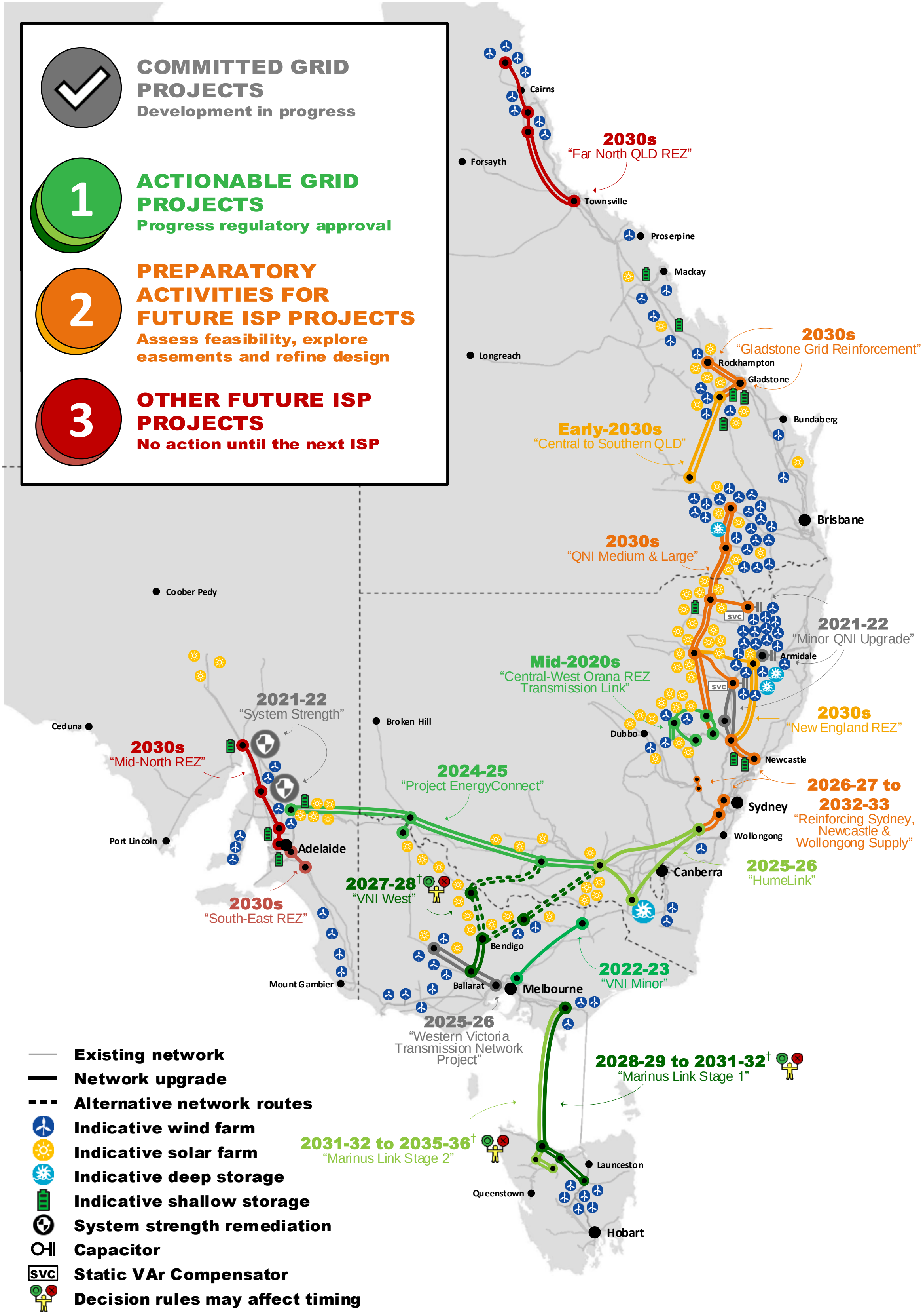
If fully implemented with the necessary market reforms, these investments will create a modern and efficient energy system that meets the system's reliability and security needs through its transition, and meets existing competition, affordability and emission policies.

- By 2035 there may be periods in which nearly 90% of demand is met by renewable generation.
- Modelling confirms that with VNI West in place, the power system would remain reliable during a 1-in-10 year summer, meeting the COAG Energy Council's Interim Reliability Measure of 0.0006% expected unserved energy.
- Assuming effective market design, $11 billion in net market benefits would be available to consumers through reduced power bills.
- Australia's target of a 26% reduction in 2005-level emissions by 2030 would be exceeded within the NEM (pro-rata share) under all scenarios.
- With VNI West and Marinus Link, regional RETs would be met in all scenarios that include these policies.

* * *

This 2020 ISP is a dynamic, whole-of-system plan that identifies the optimal development path to assist in planning regulated assets, but also highlights development opportunities and complementary market and regulatory reform needed to meet future power system needs efficiently and sustainably.

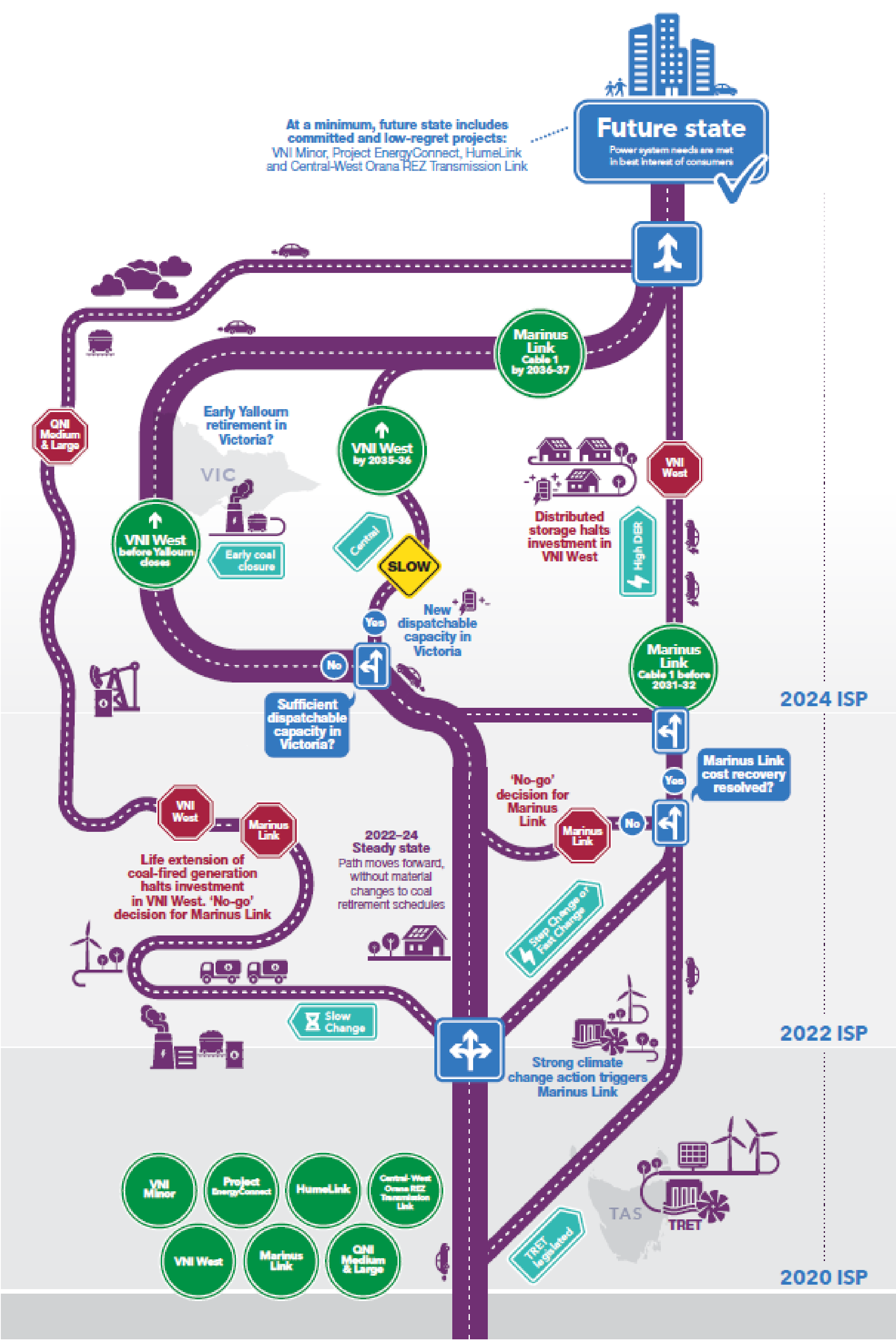
Figure 1 The optimal development path for the NEM



† The timing of these actionable projects is dependent on decision rules.

All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

Figure 2 A dynamic, whole-of system roadmap for Australia's energy future (roadmap)



Part A

A dynamic roadmap needed for Australia's complex energy transition

Australia's energy sector faces a profound, complex and accelerating transition. As its traditional generators retire, Australia must invest in a modern energy systems with significant consumer-led distributed energy resources (DER) and utility-scale variable renewable energy (VRE), supported by sufficient dispatchable resources. Digitalised power system services must leverage advances in computing and data analytics to drive greater efficiencies and increase value to consumers and investors.

The first purpose of this ISP is to set out an optimal development path for the National Electricity Market (NEM), with actionable and future transmission projects and supporting development opportunities[14]. However, the high probability of shifts in future technologies, behaviours, and business models, not to mention the complexity of the system itself, means that a single pre-determined path is not sufficient or robust.

This Part A frames the challenge for the ISP:

- Its scope is the whole NEM power system.
- Its guiding objective is to achieve power system needs in the long-term interests of electricity consumers.
- It must do so recognising the risks to consumers of investments made in uncertain times[15].
- It must therefore provide a least-regret, dynamic, resilient and transparent roadmap for the NEM through Australia's energy transition, as well as increase system resilience to better deal with future challenges.

Such an ISP will fulfil its second and more comprehensive purpose of informing power system decision-makers about the power system and its development.

A1 Covering the whole NEM power system

As a rigorous whole-of-system plan, the ISP is a far more comprehensive and richer analysis than other comparable modelling exercises for Australia's energy future.

Historically, Australia's power system has been based on large-scale power stations located around fuel centres supplying remote load centres through large-scale transmission, which is how the physical assets that comprise the current NEM were designed and built. Now, the NEM, like other power systems around the world, is undergoing a rapid transition. On certain measures, the rate of change in Australia is the fastest of any country in the world.

[14] Clause 5.22.2 of the NER

[15] Clause 5.22.10 (5)(ii) of the NER

In this context, the ISP must set out an optimal development path for the NEM's transmission assets. It does so by optimising a power system that ranges far – both technologically and geographically – over consumer-led DER investments, storage and generation investments, and demand side responses.

To optimise that system, the ISP must consider the full range of energy services required to integrate new technologies, including the vital system security services. It takes into account the capital and fuel costs of generation as well as of transmission, and opportunities for DER. It anticipates the impact of parallel shifts in coupled sectors such as transport, gas and hydrogen (see Box 1), and incorporates emerging innovations in consumer-owned DER, virtual power plants (VPPs), large-scale generation, energy storage and power system services.

The role of the distribution network in delivering the ISP requires continuing focus, especially with the growing penetration of DER and the potential impacts emerging for the main transmission network. These interactions will continue to be explored in the whole-of-system analysis in future ISPs.

Box 1: The potential of hydrogen

Hydrogen has the potential to meet some of Australia's energy needs, once it is economically competitive and the possible challenges to efficient sector integration are resolved: see Appendix 10. That potential has warranted increasing interest in hydrogen, including government and private sector plans and pilot projects, and the National Hydrogen Strategy highlights Australia's potential to be a large exporter of hydrogen.

The 2020 ISP does not incorporate quantitative analysis of the use of hydrogen within the Australian energy system, as the industry remains in the early stages of development. However, the contemplated roles for hydrogen will not invalidate the actionable ISP projects in the optimal development path.

There are varied potential opportunities and future pathways for the domestic development of hydrogen; for example, as an energy carrier, allowing renewable energy to be used to supply low-emissions energy to residences or reduce emissions from hard-to-abate industrial sectors such as steelmaking. New hydrogen transmission pipelines and existing distribution pipelines may be able to provide energy storage opportunities using hydrogen. Embedded electrolysers (utility-scale or distributed) may be able to support power system security, operability and reliability, depending on their location and operating environment and the technical capabilities of the plant.

Despite hydrogen's potential, strong policy support is needed to reduce its current high cost, build infrastructure, and otherwise create certainty and appropriate incentives in the market. There is potential for hydrogen to be competitive with diesel for use in long-distance haulage by the early 2030s, and for a green steel industry to develop if global policy shifts to support decarbonisation of the industrial sector. However, hydrogen prices need to be much lower than currently projected to compete with gas in many other domestic applications. Shipping costs and current low efficiencies are further challenges for development of an Australian export industry.

As the hydrogen sector will eventually be coupled with Australia's energy, water and transport sectors, it is critical that future hydrogen policies are coordinated with the policies and needs of those sectors.

The 2022 ISP will investigate in more detail the role of hydrogen as it relates to Australia's electricity system.

A2 Achieving system and policy needs while optimising net market benefits

The key objective for the ISP is to deliver both power system and broader policy needs in the long-term interests of electricity consumers[16].

Assuming effective and efficient markets, regulated and market-led investments together will secure the low, long-term system costs that will deliver the greatest net market benefit for consumers – including lower electricity bills.

A2.1 The public policy and power system needs

The primary policies incorporated in the ISP are the existing state and federal environmental and energy policies affecting the energy sector, including emission reduction policies and state-based renewable energy targets (RETs), and state-based (New South Wales) policies for renewable energy zones (REZs). The ISP must also address affordability, competition and consumer choice issues, within the limits set by the ISP Rules.

The power system needs are the reliability and security requirements for operating a power system within operating limits and in accordance with operating standards. Table 1 summarises the fundamental power system needs that are considered in the ISP. Primary of these is that the system remains in a satisfactory operating state through a contingency and can be returned to a secure operating state within 30 minutes.

Table 1 Power system needs considered in the ISP

Need	Operational requirements considered when developing the ISP	
Reliability	**Resource adequacy and capability** • There is a sufficient overall portfolio of energy resources to continuously achieve the real-time balancing of supply and demand.	Energy resources and strategic reserves provide sufficient supply to match demand from consumers.
		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 inertial response** • Ability to maintain system frequency within operating standards.	Frequency remains within operating standards – considering primary frequency response and frequency controls, minimum inertia requirements, availability of alternatives; system is maintained within transient and oscillatory stability limits.
	Voltage management and system strength • Ability to maintain voltages on the network within acceptable limits. • System strength above minimum levels.	Voltage remains within operating standards, fault levels are below equipment ratings, and system strength/fault levels are maintained above minimum requirements.

A2.2 Optimising the net market benefits by minimising the system's long-term cost

The ISP must use long-term total system cost as its primary measure of what is in the interest of consumers. The ideal would be to measure market outcomes such as wholesale prices or the bills paid by

[16] Clause 5.22.3 of the NER

consumers. However, these are the product of total system cost and effective market design for both regulated and unregulated investments. While total system cost can be modelled accurately based on input assumptions, market design may change over the ISP 20-year analysis period and over the typical lifetime of energy assets, and so cannot be modelled with the same rigour. Instead, the ISP has to assume that regulatory obligations and market design will be effective to attract cost-effective investment and support low total system cost. That way, low long-term system cost will translate into the best price and reliability outcomes for consumers over time. Future ISPs will better quantify the price benefits for consumers of the optimal development path.

The ISP considers the whole of the power system, including all fuel, generation, transmission, storage and network service elements[17]. The classes of costs and benefits modelled in the ISP are aligned with the categories in RIT-Ts[18]. Total system costs include all capital, operating and compliance costs of those elements[19], as well as any options lost in making a decision: see Table 2. The cost of a decision must also include any negative impact on desirable network or consumer benefits. For example, a decision that leads to consumers having to limit their desired energy use reduces the consumer benefit of on-demand energy use.

Table 2 Minimising total long-term system cost

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 doesn't play out.	Lost options/flexibility

A3 Balancing the risks and costs of making decisions in uncertain times

It would be relatively simple and certain to optimise cost, reliability and security if our energy system and its operating environment were also simple and certain. Yet the NEM is a complex system of systems. External influences change its operating environment frequently. The ISP must therefore be both dynamic and transparent. A dynamic ISP can guide market participants when the operating environment changes; a

[17] Clause 5.22.10(c)(i) of the NER

[18] Consultation Draft Cost benefit analysis guidelines May 2020

[19] Clause 5.22.10(a) of the NER

transparent ISP gives participants confidence in that guidance, particularly when they must keep options open or accept sunk costs.

A3.1 Complexity and uncertainty are unavoidable

The ISP aims to take into account:

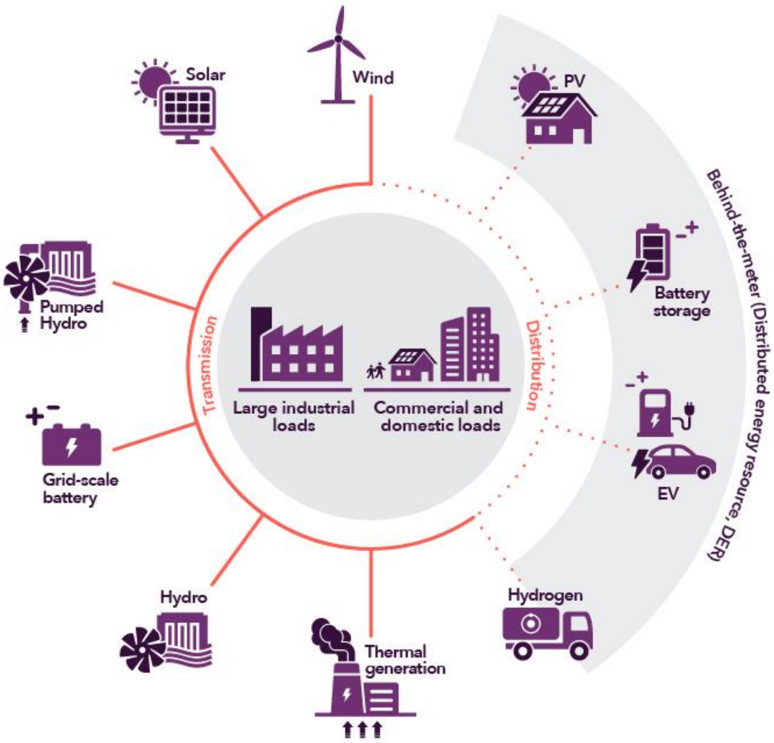
- complex and interdependent factors in the physical system, and
- changes in the future economic, trade, security, policy and technology environments.

Complexities in the physical system

The complexities include the rapid introduction of increasing levels of consumer-driven DER, satisfying the critical operational needs for the power system, arrangements to replace exiting generators and deploy replacement resources ahead of, or in alignment with, those exits, uncertainties around the market's response to these exits, low-cost but variable resources, storage, transmission investments, climate change impacts, and increasingly scarce system services.

The first major complexity is the interaction between behind-the-meter and grid-scale supply: see Figure 3.

Figure 3 Overview of power system showing interactions between grid and behind-the-meter energy supply



Consumers are increasingly managing their demand, and investing in DER, batteries and now electric vehicles (EVs). Digital controls and falling costs are making these assets easier and cheaper to adopt. Consumers can now take advantage of new business models offering VPPs. Each decision changes how and when the NEM will deliver energy. As consumers install distributed PV, the level of uncontrolled energy in the system increases, and as batteries and EVs charge and discharge, the demand profile for gridsupplied energy shifts, which in turn influences how generators operate and increases the value of flexible generation and storage.

The second major complexity for the ISP is forecasting when existing black and brown coal plants will either reduce generation or shut down. The owners of these assets will make their decisions based on a range of commercial factors, and in the context of energy and climate change policies, market arrangements, competing technologies, and social and investor licences. The ISP's objective is to maintain power system reliability and security throughout this transition.

Large thermal assets have been fundamental to the design, construction, and operation of both the physical power systems and the NEM, so the development path to replace them is fundamental in the design of future market arrangements for the NEM. While individual VRE plants may be quick to build, they are dispersed across the country, often in weak areas of the grid. At the scale and combination projected by the ISP to replace the outgoing thermal assets, they will require supporting infrastructure such as network capacity and system services to maintain system reliability and security. As individual VRE are not all developed at the same time, delivery of large-scale network access with long development lead times can be a challenging coordination task. If future market arrangements do not adequately incentivise the appropriate supporting infrastructure, under-investment could undermine future delivery of reliable, secure and affordable supply.

An accelerating complexity is achieving system resilience against a broad array of extreme weather and climate impacts. System resilience is enhanced through fuel diversity, geographic diversity and strategic redundancy. Given the increasing likelihood of extreme events, maintaining static levels of system redundancy will increase costs and risks for consumers, suggesting an incentive for earlier investment timing.

Changes to the operating environment

The potential changes to the operating environment are just as daunting as the complexities. As noted above, the energy system must be secure and reliable enough to withstand variable consumer demand and unplanned events. More changes are likely in the economic, trade, security, policy and technology environments in which the energy system operates. Australia's economy may shift towards or away from energy-intensive sectors. An emerging global hydrogen economy may offer Australia growth in a new energy-intensive export industry. COVID-19 and limits on international free trade may dampen demand for our existing energy-intensive exports, as may global security risks. Federal and state policies may restrict the availability of natural gas, underwrite new investment, or set targets for renewable energy or emissions.

A3.2 Yet investments must be made, balancing the risks of early and late action

The replacement of large-scale coal-fired power stations involves large-scale investments and deployment of new infrastructure, with long lead times and complex integration with the rest of the power system. Decisions on what and when to invest must be wise, for the consumer, the investor, and for the energy system itself. It is hard enough for investors to make such decisions within the complexity of the power system. A changing environment makes it even harder. Yet Australian consumers rely on these decisions being made for their economic and physical wellbeing. If decisions are delayed or aborted, domestic and industrial consumers will face increased costs and risks.

The ISP assumes generation investments will be guided by a well-functioning market that has appropriate signals to guide timely investments. In support of that market, the ISP aims to help identify, assess and reduce as many of the associated investment risks as possible, and offers guidance for when the operating environment changes.

The question then becomes *when* a decision on a desirable investment is needed, in the face of uncertainty. This is particularly challenging for investments with long lead times, a common dilemma for large-scale infrastructure investment, including transmission. Investing too early may lock the NEM into a development path that will be regretted in the future, possibly increasing consumers' costs. However, making decisions too late can lead to late delivery of essential infrastructure, with potentially severe consequences such as extreme price events and/or load shedding, when physical assets are simply not available to serve consumer needs. Late transmission investment can also drive higher costs to consumers in the form of investments in relatively expensive forms of generation to address short-term reliability gaps.

The ISP assesses the asymmetry between investing early, which for the right investment is typically lower cost, and investing late. Careful analysis of the risk asymmetry helps to guide when and under what circumstances investments should be made.

A4 A robust, transparent, dynamic roadmap for Australia's energy transition

The ISP uses robust and transparent cost-benefit analysis to determine the optimal development path for the NEM. However, a single static path, even if it appears optimal in 2020, will not do the job for Australia's future energy system as economic, physical and policy environments change.

This ISP is therefore a robust, dynamic and least-regret roadmap that reveals the signposts at which that path may need to change course, the options we may then have, and the complementary market reforms to make the power system resilient.

The ISP roadmap must be robust, to underpin secure, reliable, low-cost energy from the outset. It must be dynamic, given the complexity of the energy system and its changing operating environment. And it must be transparent in both process and outcomes, to give participants confidence in its guidance.

A 'dynamic' roadmap, common in making decisions on capital investments, is one that is updated to changes in the economic, physical and policy environments at regular intervals or when a particular signpost is reached. In the ISP's case, the regulated interval is every two years.

The concept of 'least-regret' decision-making is a strategic approach to managing uncontrollable future risks. (The mitigation of controllable risks can be integrated into the plan itself.) Investors can consider the potential costs or regrets from their decisions if an uncontrollable event occurs, and seek to reduce those regrets as far as practicable. The ISP must similarly consider any potential regrets on behalf of consumers. For example, a decision not to upgrade a transmission line to access new generation sources until after an aging power station retires may be regretted if that power station closes earlier than expected. These regrets translate to additional costs or lost opportunity, and, in the worst case, an unreliable power system. All these outcomes will increase costs to the consumer.

To minimise these regrets and deliver the best outcomes for consumers, AEMO uses the ISP to determine whether to invest now in the option with the least downside risk, or defer investment until there is more certainty, or stage investment or select options that retain flexibility, or invest in a way that hedges major risk.

Part B
Consultation and modelling to meet the ISP objectives

AEMO uses scenario modelling and cost-benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition. Exploring scenarios helps assess the risks, opportunities and development needs through the energy transition, in the long-term interests of consumers.

To do so, the selected scenarios must cover a broad range of plausible operating environments for the energy sector, and the potential changes in those environments, in an internally consistent way. The extensive ISP stakeholder consultation and engagement process to determine the assumptions and inputs for these scenarios and sensitivities is discussed below, and in more detail in Appendix 1.

Part B sets out how AEMO has used scenario modelling to explore the net market benefits of possible energy investments, having regard to the Draft AER Cost Benefit Analysis Guidelines:

- Developing scenarios, inputs and assumptions through extensive consultation.
- Selecting five scenarios and six sensitivities to span all plausible operating environments.
- Conducting economic and power system modelling to identify the least-cost development paths for each scenario.

The following Part C summarises the non-grid development opportunities that this modelling suggests will be needed for Australia's future energy system. Parts D and E then turn to the nature and timing of needed transmission investments. AEMO again stresses that this is one system, so any change to investments in transmission will change the optimal non-grid investments, and vice versa.

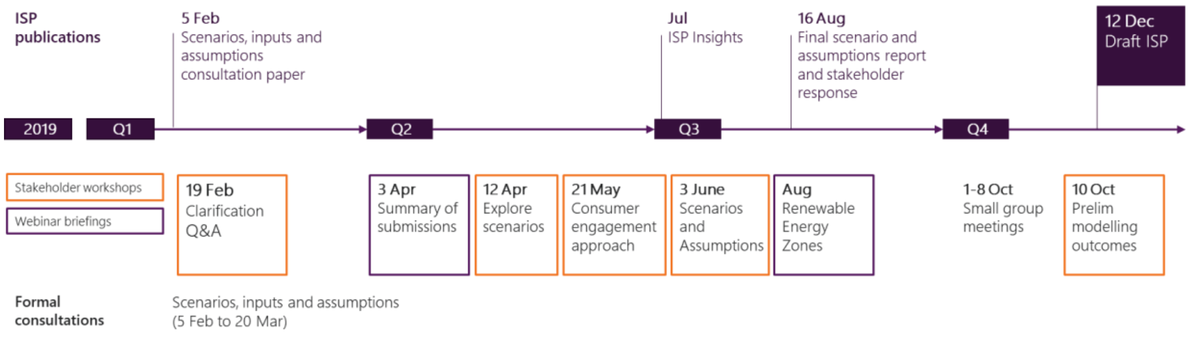
B1 Effective consultation for the 2020 ISP

For the 2020 ISP, AEMO consulted extensively with industry, academia, government, developers and consumer representatives through two rounds, one before and one after the publication of the Draft 2020 ISP in December 2019.

B1.1 Round 1: Scenarios, inputs and assumptions

The first round of consultation was on the scenarios and associated input assumptions to be used for modelling for the Draft 2020 ISP: see Figure 4. The ISP benefited from the insights of over 100 industry and consumer stakeholders, through 25 detailed written submissions, four workshops and numerous stakeholder meetings.

Figure 4 Consultation for Draft ISP



The consultation culminated in the *Forecasting and Planning Scenarios, Inputs and Assumptions Report* (August 2019)[20], an essential source document for this ISP. It sets out the detail and sources of all the inputs and assumptions on which the ISP relies, including:

- **Demand and supply inputs**, including energy consumption forecasts, EV adoption, and policy, technical and economic settings that affect energy supply.
- **Generation and storage inputs**, including existing generation assumptions, the uptake of DER, gas and electricity system co-dependencies (allowing for domestic gas use and LNG exports). For generation technology cost options, AEMO partnered with the CSIRO on the GenCost project[21], working collaboratively with industry to annually review and update projections of electricity generation technology costs.
- **System variables** that need to be considered in the analysis, including system security constraints, network losses and Marginal Loss Factors (MLFs), system strength and inertia requirements.
- **Market modelling** approaches for both gas and electricity markets, including approaches to improve representation of storage modelling, better capture the effects of weather on the system and the need to build greater power system resilience[22]. Improvements in modelling to better assess the revenue sufficiency of existing thermal fleet have also been consulted on.
- **Network development options,** including REZs, interconnector augmentation options and non-network technologies. The REZ options were developed initially with DNV-GL[23] and with wide stakeholder consultation in 2017. For the 2020 ISP, AEMO has refined these candidate REZs against regional policies and inputs, and each candidate REZ's features and transmission needs are set out in Appendix 5.

[20] AEMO has reported on how that feedback has been taken into account, and provided an Excel workbook containing data inputs: see AEMO 2019 Scenario, Input and Assumptions report and Inputs and Assumptions workbook v1.5 on the NEM Forecasting and Planning web page, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning

[21] CSIRO, GenCost 2018 Updated projections of electricity generation technology costs, December 2018, at https://publications.csiro.au/rpr/download?pid=csiro:EP189502&dsid=DS1

[22] Changes in the future climate, including an increasing number of extreme weather events, can increase stress on the power system, so it is important that the system is resilient to these risks. The Australian Government is providing $6.1 million over three years, from 2018-19, to fund the Electricity Sector Climate Information (ESCI) project. Through this project, CSIRO and Bureau of Meteorology in collaboration with AEMO will deliver specific information and data to the electricity sector to improve the reliability and resilience of the NEM to the risks from climate change and extreme weather. https://www.environment.gov.au/climate-change/adaptation

[23] DNV-GL, Multi-Criteria for Identification of Renewable Energy Zones, April 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf

- **Transmission project options** were refined in consultation with transmission network service providers (TNSPs) through joint planning and extensive power system engineering, to ensure robust technical designs were used in the modelling. For major interconnections, many options were assessed encompassing differing routes, design implementation, staging, and alternatives including non-network options. For example, for the major new interconnections between New South Wales and Victoria, and New South Wales and Queensland, over a dozen headline options were assessed covering differing routes, voltages, capacities, non-network optimisation and design options. A full listing of options considered is in Appendix 3.

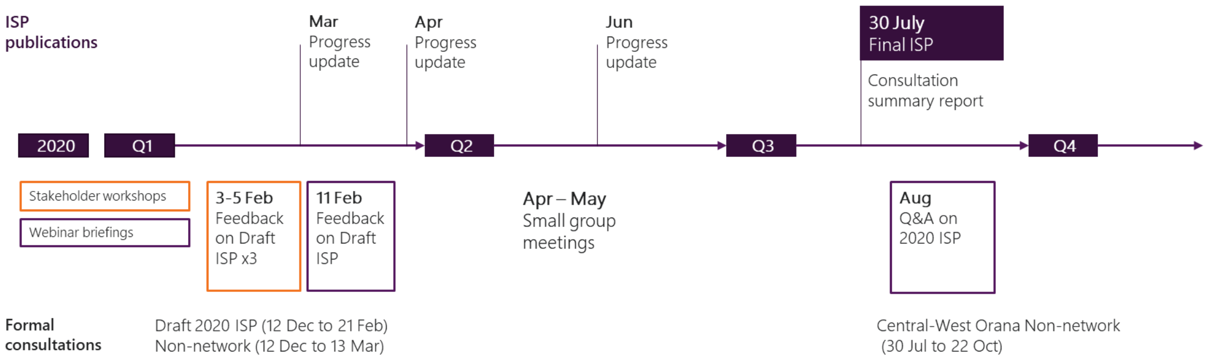
B1.2 Round 2: Review of Draft 2020 ISP

AEMO released its Draft 2020 ISP on 12 December 2019 and has consulted extensively on the draft since. Over 170 industry, regulator and consumer stakeholders have shared their insights, through multiple public workshops and webinars, formal written submission processes, and targeted one-on-one discussions with government, industry and consumer groups. Our website has also published non-confidential written submissions and three ISP progress updates, each of which has stimulated further feedback. The second wave of consultation resulted in a number of material changes to inputs, discussed in detail in the *2020 ISP Consultation Summary Report*[24].

Insights accumulated from the consultations have added to targeted refinements of inputs and assumptions since the Draft 2020 ISP. In particular, the introduction of the Tasmanian Renewable Energy Target (TRET) in some scenarios and significant transmission cost increases have had an impact on the development sequence and timing of actionable ISP projects. As a result, AEMO has had to remodel, extending the analysis in areas requested by stakeholders, and updating the list of committed and anticipated generation projects.

For final data inputs used in this ISP analysis refer to: *AEMO 2020 ISP Inputs and Assumptions workbook*.

Figure 5 Second round of consultation and engagement for the 2020 ISP



The following changes occurred through the second round of consultation:

- **Changes in operating environment:** COVID-19 has changed near-term demand, supply and risks in the energy sector, and record distributed PV sales in 2019 have changed the long-term trends.
- **Changes in regional policies:** Tasmania has announced the TRET, proposing to legislate this later in 2020, and aimed to support 200% renewable energy generation in Tasmania by 2040. New South Wales

[24] https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

has firmed up its commitment to develop the transmission needed to accommodate 3 GW of large-scale VRE in the Central West REZ. Victoria is procuring a 250 MW battery to enable up to 250 MW of increased imports from New South Wales to Victoria.

- **Changes in input costs:** each major transmission project identified in the ISP that had gone through the RIT-T process had at least a 30% increase in cost from initial estimates, due to a range of factors. As a consequence, AEMO, in collaboration with the responsible TNSPs, increased the capital cost estimates by approximately 30% and adjusted for the specific project circumstances for each ISP projects. Costs of grid-scale batteries reduced by 30-40%. New gas-powered generators are expected to be smaller than originally assumed, leading to cost increases of 30-60%. Cost expectations for new pumped hydro energy storage increased by 50%. Other technology costs have adopted projections from the CSIRO's 2020 GenCost report.

Some of these changes have been embedded within the ISP modelling, whereas others have been used to test whether the ISP is sensitive to the change.

Despite these changes, the key findings of the Draft 2020 ISP – concerning the speed of Australia's energy transition and the need for dispatchable resources as existing generators retire – remain valid, highlighting the robustness of the scenarios and approach used in developing the ISP.

B2 Scenarios and sensitivities to span all plausible operating environments

The ISP continues to project a continuing and profound transition of the NEM over the next two decades. As stated in the 2018 ISP, our energy system is transitioning from one dominated by coal-fired generation to one of diverse renewable and distributed energy resources, supported by dispatchable resources and network solutions. This outcome has been consistently generated by all AEMO and peer iterative modelling since the Finkel Review, and has been adopted and confirmed throughout the consultations. The pace of development in new renewable and distributed energy generation has been even faster than anticipated in the 2018 ISP.

To explore plausible futures through this transition, AEMO has developed and set through extensive consultation:

- five scenarios that span differing rates of change in technology development, renewable and distributed generation, decarbonisation policies, and the electrification of other sectors such as transport, and
- four sensitivities that represent risks TNSPs may need to consider in their RIT-T process, and
- two key policy and demand assumptions that have potential to change in the near term and may materially influence outcomes.

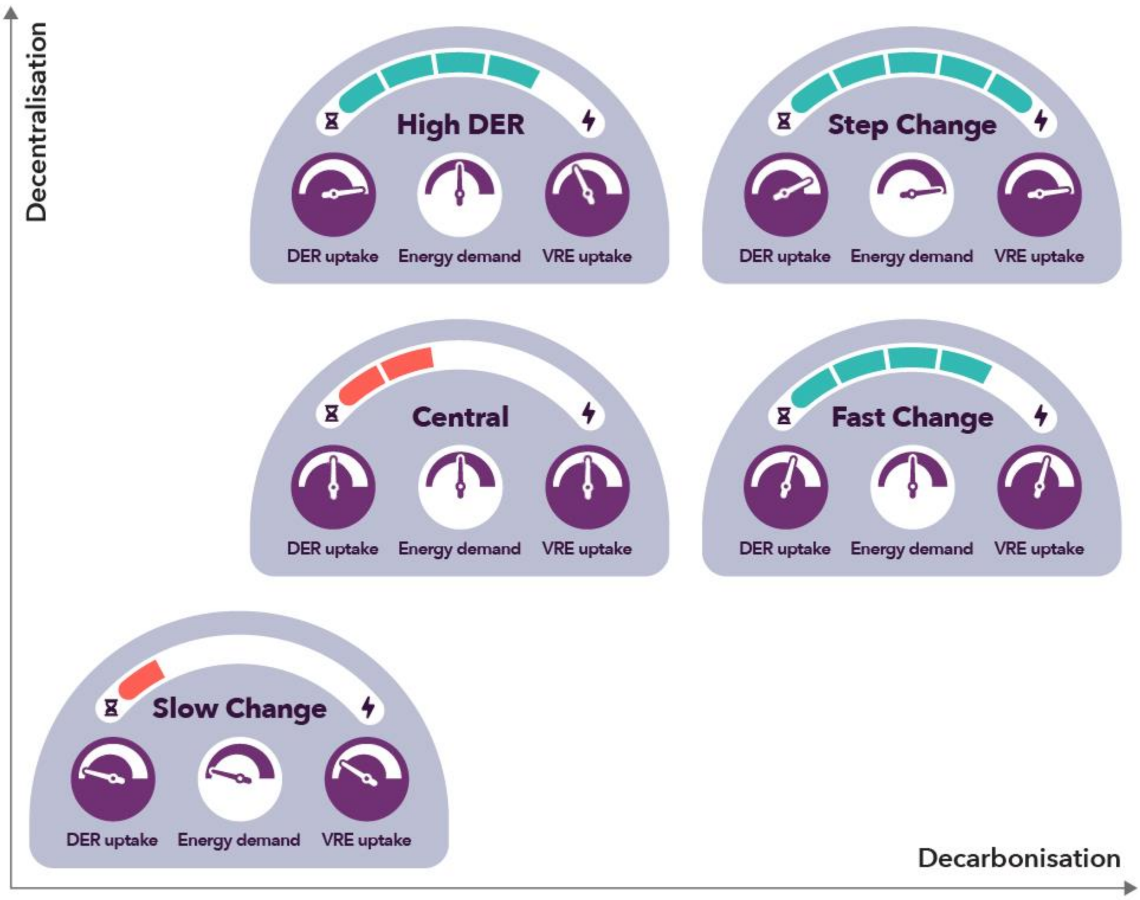
B2.1 The Central Scenario and variations in the speed of transition

A candidate ISP development path is only considered justified when it is assessed as likely to deliver net market benefits under the **Central scenario**.

In the Central scenario, the pace of transition is determined by market forces under current federal and state government policies (outlined below). The other scenarios are variations in the pace of the transition – one slower than the Central scenario, and three faster: see Figure 6:

- **Slow Change scenario:** a slow-down of the energy transition, characterised by slower changes in technology costs, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction.
- **High DER scenario:** a more rapid, consumer-led transition, as consumers take control of their energy costs with easy-to-use, interactive technologies, falling costs for DER and EVs.
- **Fast Change scenario:** a more rapid technology-led transition, its costs reduced by advancements in grid-scale technology and targeted policy support. There is coordinated national and international action to reduce emissions leads to innovation, automation, the accelerated exit of existing generators, and greater electric transport.
- **Step Change scenario:** both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation and strong infrastructure commitments.

Figure 6 Comparative rates of decarbonization and decentralization across the five ISP scenarios



Current policies incorporated into the Central scenario

A policy is relevant in determining power system needs if there is either a commitment made in an international agreement or enacted in legislation in Australia, there is a regulatory obligation, there is material funding in a state or federal government budget, or otherwise if COAG has advised AEMO to incorporate the policy[25]. The Central scenario therefore incorporates:

[25] Clause 5.22.3(b) of the NER

- the NEM's share of the Federal Government objective of reducing emissions by at least 26% by 2030
- Renewable Energy Targets in Victoria (VRET, 50% by 2030), Queensland (QRET, 50% by 2030) and Tasmania (first phase of TRET, 100% by 2022)
- the New South Wales Electricity Strategy[26] (Central-West Orana REZ Transmission Link)
- the Snowy 2.0 energy storage project, and
- all current state and federal policies impacting DER and energy efficiency policies at the time the demand forecasts were developed[27].

Different policy assumptions are used for the other scenarios in line with the scenario narratives, as set out in Table 3.

Table 3 Policies incorporated in each scenario

Policy	Slow Change	Central	Fast change	High DER	Step Change
VRET – 40% by 2025, 50% by 2030	✓	✓	✓	✓	✓✓
TRET - 100% by 2022	✓	✓	✓	✓	✓
TRET - 200% by 2040	×	×	×	✓	✓
QRET – 50% by 2030	×	✓	×	✓	✓✓
Central-West Orana REZ Transmission Link	✓	✓	✓	✓	✓
Snowy 2.0	✓	✓	✓	✓	✓
Current DER and EE policies	✓	✓	✓	✓✓	✓✓
26% reduction in emissions by 2030 (NEM)	✓	✓	✓	✓	✓✓
NEM carbon budget to achieve 2050 emissions levels	×	×	✓	×	✓✓

✓ included in the scenario, × excluded in the scenario
✓✓ included at a minimum, but volume likely to be exceeded based on scenario narrative.

B2.2 Market event sensitivities

Through consultation, AEMO has identified additional sensitivities to complement the scenarios and test the robustness of the power system. AEMO has tested sensitivities to material changes in the entry or exit of major projects, generators or loads.

The first four market event sensitivities focus on consumer risks associated with variations in timing of key new projects, or generation/load closures:

[26] https://energy.nsw.gov.au/government-and-regulation/electricity-strategy

[27] That is, August 2019 for the Central scenario. The updated demand sensitivity captures any additional policies affecting electricity consumption that were introduced before June 2020.

- **Delay of Snowy 2.0:** if the project was delayed unexpectedly without replacement.
- **Early coal closure:** if a brown coal power station reduces generation earlier than its submitted retirement – a reduction is possible through early retirement, seasonal mothballing or long-term maintenance.
- **Central-West Orana REZ:** if the New South Wales Electricity Strategy attracts at least 2 GW of additional VRE in the Central-west Orana REZ by 2028.
- **Closure of industrial load:** if industrial load in both Victoria and Tasmania closes in 2021-22.

As these represent risks that may need to be considered by TNSPs in their RIT-T process, they have been treated as additional scenarios and modelled independently throughout the ISP cost-benefit analysis. They adopt the Central scenario assumptions for all other inputs.

B2.3 Recent changes in policy and demand assumptions

Another two sensitivities relate to recent revisions in inputs or near-term policy decisions that could constitute a material change. These were applied towards the end of the ISP process, to inform selection of the optimal development path:

- **Inclusion of TRET:** if the announced TRET is legislated, to support 200% renewable energy generation in Tasmania by 2040.
- **Updated demand**: testing materiality of the changes in the Central scenario demand forecast developed for the 2020 Electricity Statement of Opportunities (ESOO)[28] that captures the estimated impact of COVID-19 as well as the record distributed PV sales observed in 2019[29].

B3 Modelling to identify the least-cost development path across all scenarios and market event sensitivities

AEMO used scenario and cost-benefit analysis to determine the least-cost development path to achieving power system needs in each individual scenario and market event sensitivity, and used this analysis both to determine the ISP development opportunities (Part C) and the actionable and future ISP network projects (Parts D-E) that make up the optimal development path.

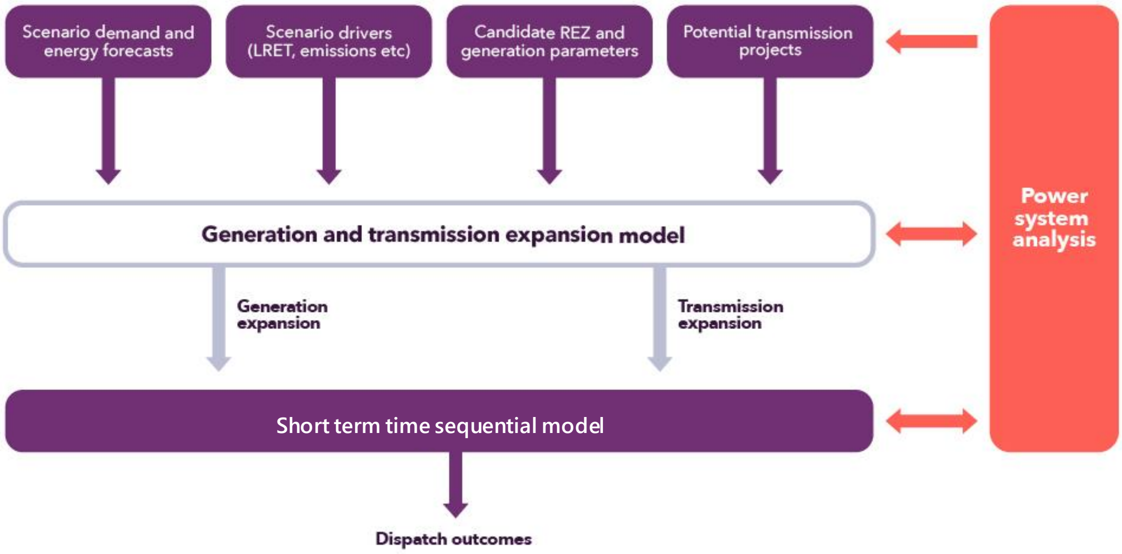
B3.1 Integrated economic and power system modelling

Even within one scenario, there are near-infinite possibilities to mix generation, storage, transmission and DER to meet cost, security, reliability and emissions expectations. To determine the optimal supply mix, AEMO ran the multi-phase integrated modelling shown in Figure 7.

[28] To be published in August 2020

[29] Distributed PV forecasts are provided by two independent consultants, CSIRO and Green Energy Markets, available at:
CSIRO: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf
Green Energy Markets: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf

Figure 7 Multi-phase integrated modelling to determine the optimal supply mix for each scenario



AEMO first ran the NEM generation and transmission expansion model (see Box 2 below) to identify the most economic way to meet projected consumer demand. As options for network augmentation were refined, the modelling re-evaluated the generation and storage mix. Eventually, the modelling revealed the lowest-cost (net present value [NPV]) outcome for the location and staging of resources as well as the optimal evolution of the network configuration.

To verify that these outcomes would deliver the desired system reliability and security performance, they were then tested in a suite of short-term models, using time-sequential half-hourly modelling of snapshot years, to assess detailed transmission constraints, unit commitments and bidding behaviour. These results were also tested in a detailed power system model (see Box 2) to ensure system security. Where necessary, the leading outcome for each scenario was iterated in the time-sequential model until the optimal outcome was identified.

Box 2: Models for economic and power system outcomes

For the economic outcomes, AEMO used PLEXOS® software to model the gas, electricity, storage and transmission investment that would minimise the total system cost while meeting reliability and emission expectations. The modelling incorporated:

- options for energy storage, particularly in combination with VRE to substitute for retiring coal generators,
- DER co-ordination so that distributed generation and storage could help meet system as well as consumer needs, and
- in the relevant scenarios, state renewable energy targets and 2050 carbon budgets as hard constraints that must be achieved, with the latter leading to year-on-year emission trajectories determined by PLEXOS®. No carbon price was used in any scenario.

For the power system analysis, AEMO relied on PSS®E tools, including loadflows, fault levels, dynamics and reactive power/voltage control. AEMO also applied the outcomes of previous modelling using PSCAD™ that defined detailed requirements for inertia and other system security services. The modelling considered options for alternative network and non-network infrastructure:

- High voltage alternating current (HVAC) was generally preferred for the major ISP projects, designed to share diverse resources across areas and regions. High voltage direct current (HVDC) was generally more expensive due to the multiple convertor stations needed to connect REZs and VRE along the route. HVDC could be used in more targeted areas, such as point-to-point connection of individual VRE projects, or for connections within REZs.
- Targeted application of non-network technologies such as modular power flow controllers and other static devices will be critical to optimise power flows in the augmented network: see Appendix 3.
- While batteries were considered to offset capacity needs, HVAC solutions were generally preferred as large-scale (1-3 GW) augmentations are needed to provide large-scale transfer capacity and fulfil REZ needs. Batteries should be explored for incremental gains when finalising the designs of the transmission projects in the RIT-Ts.

B3.2 Calculating the NPVs of net market benefits using cost-benefit analysis

To enable candidate development paths to be compared, AEMO's first task is to determine the NPV of their net market benefit – that is, the reduction in their total system cost relative to a counterfactual in which there are no further transmission developments beyond projects already committed: see Figure 8.

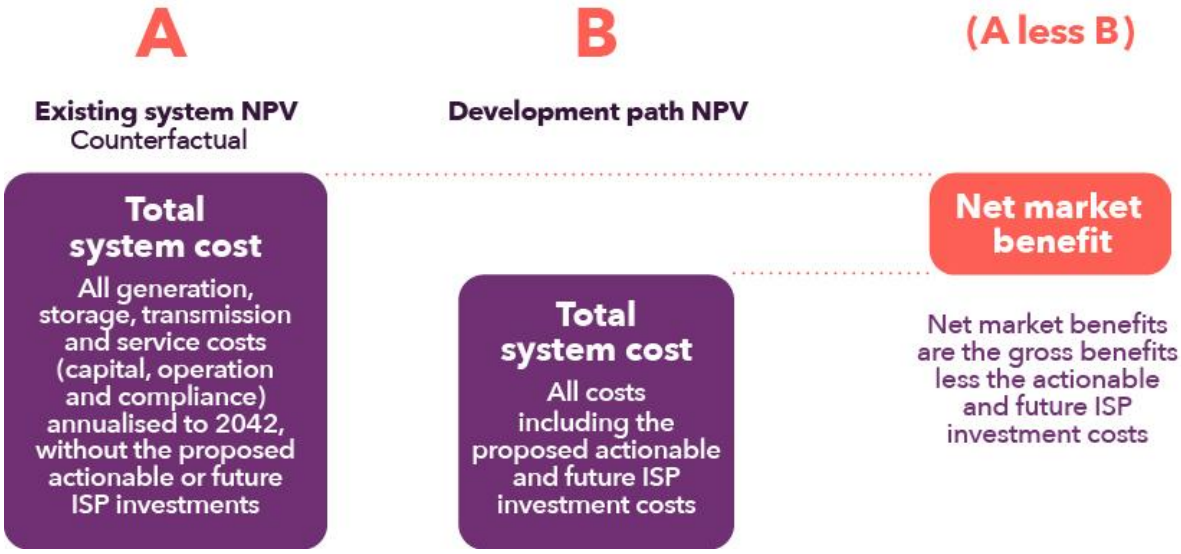
For this ISP, the NPV represents the present value of annual costs and benefits from now (2019-20) until 2042. Capital investment in generation, storage and transmission infrastructure was converted into an equivalent annuity to allow like-for-like comparison on assets with different economic lives. No terminal value was included, on the assumption that benefits associated with the transmission development continue to accrue at similar (or greater) levels beyond 2042. This is a reasonable assumption to make if one believes that the NEM will continue to transition away from coal-fired generation and towards renewable generation.

As an example, the least-cost development path for the Central scenario includes investments in ISP projects (outlined in Part D) totalling approximately $11 billion. When each investment is annualised over its lifetime, the annual network capital cost is approximately $690 million per annum by 2042. This is an NPV of approximately $3.1 billion from now until 2042 (or $3.5 billion including annual maintenance costs). For more details of this approach and the calculation of the equivalent annuity, refer to Appendix 2.

In most scenarios, AEMO applied the discount rate of 5.90% (real, pre-tax) for NPV calculations, consistent with the RIT-T guidelines. Applying a risk premium to emissions-intensive generation technologies is unlikely to significantly impact the outcomes, given technology cost movements of renewable energy projects relative to thermal alternatives. The Slow Change scenario's settings are associated with lesser economic stimulation, challenges to trade flows and lower economic conditions. To account for the more challenging economic environment, which is likely to result in lower returns and a generally greater challenge to make major investments, AEMO used a higher discount rate of 7.90% as a simple way to account for these issues in the decision-making process.

As shown in Figure 8, when conducting whole-of-system planning, the least-cost development path is also the development path that maximises net market benefits. This is because the development paths include generation and storage developments and their fuel costs as well as transmission developments and other associated infrastructure.

Figure 8 Cost-benefit analysis calculation of net market benefits of development paths



B3.3 Least-cost development path under each scenario

The maximum NPVs achieved, assuming perfect foresight, by the least-cost development path for each of the different scenarios are set out in Table 4 below. They are defined by the ideal timing of major transmission, generation and storage projects, that the economic and power system modelling reveal would reliably deliver energy resources as needed by consumers, while meeting policy objectives. These projects and timings are set out in Section D2.1, where the specific results of the modelling approach are taken up in determining the optimal development path for those projects.

Table 4 shows that while grid investment delivers a positive net market benefit (NPV) in all scenarios, the benefit ranges enormously, from $56 million (in the Slow Change scenario) through to over $40 billion (Step Change scenario). This underscores what is at stake in the timing and selection of projects in the ISP's optimal development path.

The gross benefits reflect the full range of categories discussed in Section A2.2 above. In the Central scenario, the major contributions are lower fuel costs after reducing reliance on conventional generation ($10 billion), the deferral of generation capital costs ($0.6 billion) and the reduction in fixed and variable operating and maintenance costs ($1.2 billion). These benefits derive from sharing resources more effectively across the NEM. They would also create competition in the market to put downward pressure on consumer prices, and secure cost savings in voluntary curtailment (demand side participation [DSP], $0.1 billion).

Table 4 Scenario analysis showing benefit of transmission investment (NPV, $ million)†

	Net benefit ($M)				
Benefit category	**Central**	**Slow Change**	**Fast Change**	**Step Change**	**High DER**
Capex	$570	$389	$7,951	$23,842	$768
FOM	$692	$917	-$872	$3,704	$888
Fuel	$10,045	$1,046	$11,339	$18,670	$6,250
VOM	$511	-$2	$383	$722	$293
USE+DSP	$124	$19	$148	$128	$86
Rehabilitation costs‡	-$10	-$52	$251	$33	-$9
Gross market benefits	$11,932	$2,317	$19,200	$47,099	$8,276
Network	-$3,530	-$2,255	-$1,008	-$4,407	-$3,746
Generic REZ network costs#	-$714	-$6	-$3,814	-$1,955	-$526
Total net benefits	$7,688	$56	$14,379	$40,738	$4,004

† Note that absolute total net benefits across scenarios should not be compared as they are based on different assumptions, not all of which directly relate to the energy sector.
‡ Rehabilitation costs refers to the costs associated with retiring a power station, including site rehabilitation.
# Generic REZ network costs represent the estimated cost of increasing hosting capacity for future REZ where specific ISP projects have not yet been identified.

Part C
ISP development opportunities

The objective of an ISP is to minimise long-term total system costs, thereby maximising benefits in the interest of consumers, while meeting the NEM's reliability, security and emissions expectations. Part B set out the scenario modelling approach used to test the extent to which alternative sets of investments would meet those objectives.

This Part C starts to lay out the results of that modelling. It describes the non-grid changes and investments that are needed, in tandem with network investments, to meet the ISP's objectives through to 2040. These are the ISP development opportunities that form part of the optimal development path, with ISP network projects being the subject of Parts D and E.

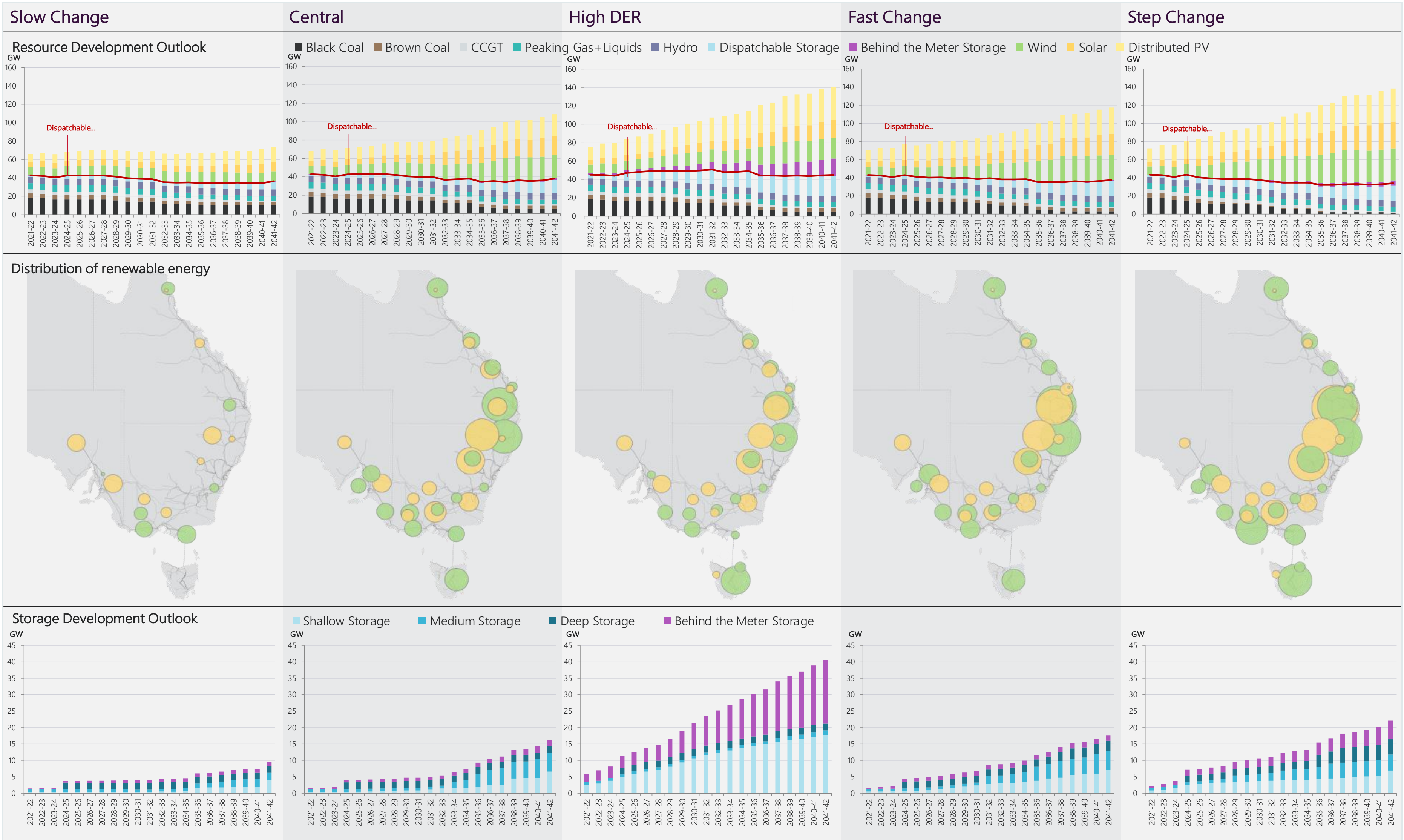
ISP development opportunities are projects that do not involve a network or non-network option and include distribution assets, generation, storage projects, or demand side developments that are consistent with the efficient development of the power system. While the National Electricity Rules (NER) pave the way for actionable transmission projects through the RIT-T process, there is no similar regulatory mandate for generation and storage resources to be built. Rather the ISP offers a signal to inform the decisions of private developers. Market design is crucial for both regulated and private investment to deliver the least-cost outcome for consumers. Without adequate changes to market design, currently being considered by the Energy Security Board (ESB), it is unlikely that the existing market mechanisms will deliver the optimal outcomes reported here. Without improved markets, consumers will ultimately have to pay higher prices for these sub-optimal outcomes.

Across all scenarios, the NEM is evolving from a centralised coal-fired generation system, to a highly diverse portfolio dominated by DER and VRE, supported by enough dispatchable resources to ensure the power system can reliably meet demand at all times. In that transition to 2040:

- coal-fired generation is expected to fall from 23 GW to 9 GW, in line with announced retirements
- small-scale DER are expected to double, and in some scenarios triple, by 2040, holding grid demand relatively constant
- over 26 GW of new grid-scale VRE will be needed beyond what is already committed and anticipated (in all but the Slow Change scenario) to meet that demand; most of this will be in REZs that maximise the value of geographic weather diversity
- 6-19 GW of new dispatchable resources will be needed in support to firm up the inherently variable renewables, and
- investments in power system services will be needed to support a system no longer dominated by centralised thermal generation with large spinning generators.

The pace of the transition varies by scenario, although the trends are very consistent: see the double-page Figure 9 overleaf. Ultimately, the NEM will draw on a technologically diverse mix that may diversify further as emerging technologies mature, to minimise long-term total system costs, meet reliability and security expectations, and reduce emissions significantly.

Figure 9 Power system development in each least cost development path across the five scenarios*



* Behind the Meter storage includes all distributed storages that are not dispatchable; Dispatchable storage includes all types of dispatchable storage regardless of depth (including VPP). In bottom charts, dispatchable storage is further split into: Shallow storage (up to 2 hours duration), Medium storage (4 to 12 hours duration) and Deep storage (24 hours or more duration).

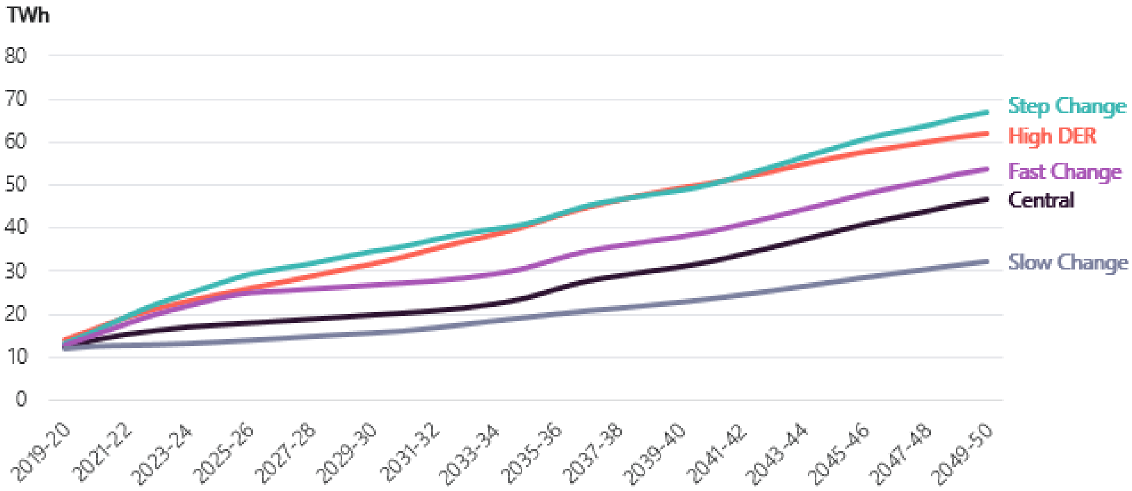
C1 Distributed energy resources expected to double or even triple by 2040

All scenarios expect to see residential, industrial, and commercial consumers continue to invest heavily in distributed PV, with increasing interest in battery storage and load management. This may bring diverse consumer-led benefits to the wider economy – for example spurring additional market and technology innovation – as well as offering power system flexibility, reducing demand for grid-scale investment and creating employment opportunities in the energy sector. However, regulations, standards, digital platforms and distribution-level investments must be in place to allow DER investments to be able to contribute to their full potential.

C1.1 Growth of DER

AEMO projects that DER could provide up to 13% to 22% of total underlying annual NEM energy consumption[30] by the end of the outlook period. The growth in DER is driven primarily by continual installation of distributed PV on domestic and commercial premises: see Figure 10.

Figure 10 Distributed PV generation to 2050



Note: Includes PV non-scheduled generation (PVNSG).

Together with energy efficiency and local storage, that growth is forecast to keep grid demand held more or less constant over the outlook period, even though the population and economy are growing. In most scenarios, EVs are forecast to have only a small impact on overall NEM energy consumption[31]. That said, subject to how future regulations, incentives and infrastructure shape charging profiles, impacts of EVs on local instantaneous network demand can range from significant to benign. This ISP assumes a well managed roll-out of EVs with only limited and manageable system impacts. See Appendix 10 for further discussion of EVs in this ISP.

This growth in DER may lead to much lower troughs of minimum operational demand in the NEM, increasing the need for new sources of critical system services: see Section C4. The extent of

[30] Total annual underlying NEM energy consumption, including distributed PV, and PVNSG (commercial-scale PV, behind the meter and <30 MW per installation). The level of instantaneous uncontrolled power that will need to be operationally managed at times of DER peak export will be much higher.

[31] In the Step Change scenario, EVs account for 12% of underlying 'power point' NEM consumption by 2040.

that effect will depend on the uptake of behind-the-meter storage to complement distributed PV, the size and scale of load flexibility and load shifting capability, and the times of EV charging.

C1.2 Technical and market integration of DER

The ISP assumes that the necessary regulations, standards, digital platforms and distribution-level investments are in place to allow DER investments to contribute to their full potential. This will not happen automatically. A number of technical and market changes are needed to manage two-way flows, the impacts of DER on faults on the system, peak demand, minimum demand and peak export from DER.

Technical integration

As DER penetration continues to increase, new installations need sufficient interoperability capabilities to maintain power system security. For example, all distributed PV will need mandatory feed-in management capability. DER providing a large proportion of energy in a region will need, as a condition of connection, similar capabilities as scheduled/semi-scheduled generation. This will avoid limits to uncontrollable generation being imposed in certain conditions and regions to maintain power system operabilility. As well, cyber security measures are needed to avoid unintended system security risks. This requires industry collaboration and potentially a new regulatory lever to establish a single interoperability platform.

The initiatives needed to ensure technical integration of DER are set out in Box 3.

Box 3: Technical integration of DER

Technical integration means ensuring operational tools operate effectively in a high-DER world. The key initiatives needed include:

- **Standards and protocols** – uplift the DER inverter standard AS4777.2 to improve device responses during power quality disturbances[1], implement standards to provide cyber security protocols and interoperability at the device level, improve the compliance framework to ensure devices perform to the agreed standards, and finalise review and implementation of demand response standard AS4755.2.
- **Visibility** – explore options to get real-time visibility of DER (at a suitable level of aggregation – e.g. zone sub-station or transmission connection point) to support operational decision-making.
- **Operation** – define the technical envelope for secure operations under minimum demand scenarios, implement improved dynamic models for load and DER, improve capability for investigating and understanding DER behaviour during disturbances, amend Emergency Frequency Control Schemes and System Restart arrangements, and prepare for artificial intelligence and other machine learning tools to manage the variable and diverse resources in the system.

Market integration

Market/regulatory integration is needed over the next two to three years to open the market up to new participants, products and system services, and to digitalisation. Three projects are currently planning that integration:

- **Open Energy Networks**: to govern optimisation of DER in the distribution network. Energy Networks Australia (ENA) and AEMO are working on proposals to integrate DER and distribution constraints into wholesale markets, and for distribution network service providers (DNSPs) to extend their technical capability to monitor, calculate and communicate network constraints for DER.
- **DER Integration Market Design Initiative (MDI):** part of the ESB's Post 2025 NEM redesign project, to ensure DER integration is a key consideration in the design of the two-sided market, the ahead market, and new essential system services. The DER Integration MDI recommends milestones for DER integration based on DER uptake and customer engagement, network congestion and the use of DER to provide network services.
- **Wholesale Demand Response rule changes**[32]**:** have been made by the Australian Energy Market Commission (AEMC) to enable aggregators to bid demand response directly into the wholesale market, as a substitute for conventional supply, as well as access and pricing reforms. The rule change is scheduled to be implemented in October 2021.

AEMO is also leading three initiatives to pilot DER capabilities and generate operational and consumer insights, among a range of trials occurring across the industry:

- The AEMO/Australian Renewable Energy Agency (ARENA) three-year demand response strategic reserve trial is in its third year.
- AEMO's VPP trial was launched in October 2019.
- AEMO is working with parties to design a DER marketplace trial that leverages the Open Energy Networks project.

C2 Over 26 GW of new VRE needed to replace coal-fired generation by 2040

While overall grid consumption is being held constant by DER, new generation capacity is needed to replace retiring plants. To fill that gap, AEMO forecasts that Australia should invest in a further 26-50 GW of new large-scale VRE beyond existing, committed and anticipated projects – most optimally in REZs – supported by essential storage, gas-powered generation (GPG), DSP and transmission investments. Some of this additional supply will be needed to make up for the losses that occur during the energy storage cycle.

C2.1 VRE requirements to replace retiring coal

In all but the Slow Change scenario, existing coal-fired plants are not forecast to continue beyond their planned retirement dates: see Figure 11. In fact, in the Fast and Step Change scenarios, we expect them to exit earlier if competition from renewable generators and carbon budgets reduce their revenue below what is economic for them to continue.

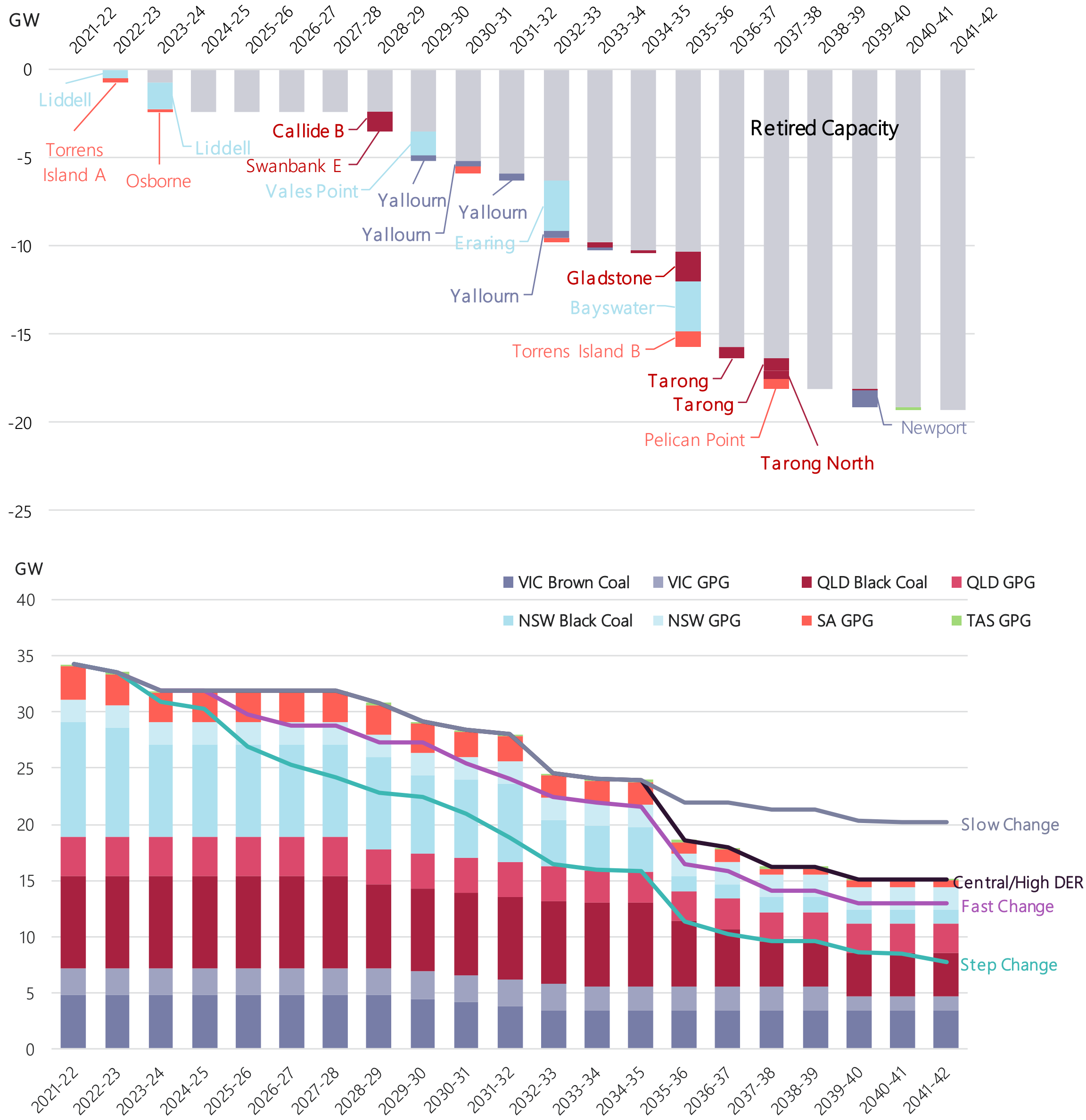
Strong economics and state RETs are continuing to drive VRE, with 10 GW currently installed or in commissioning[33] and another 6 GW expected to be operational in the next two years, as either committed or anticipated projects. An additional 31 GW is forecast to be needed by 2040 in the

[32] AEMC, Multiple Rule Change Proposals 2019, Wholesale Demand Response Mechanism

[33] AEMO Generation information, February 2020 update

Central scenario. In the Step Change scenario, up to 50 GW would be required, with Queensland and New South Wales each forecast to add over 16 GW and Victoria over 7 GW by 2040.

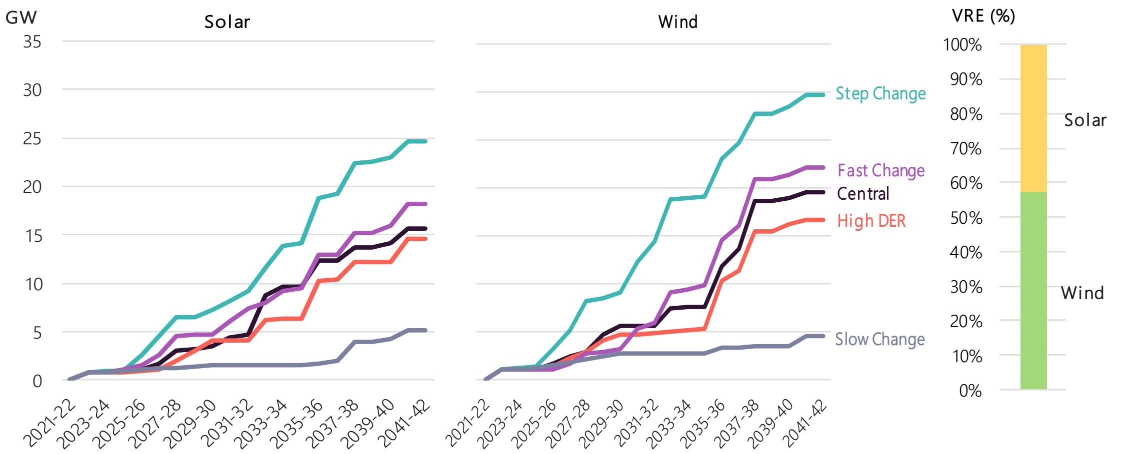
Figure 11 Coal-fired generation and GPG retirements (top) and capacity (bottom)



Note: Based on expected closure years provided by participants as of February 2020. In July 2020, CleanCo Queensland advised that the Swanbank E generator would defer its planned closure year to 2036. We do not consider this delayed retirement to materially impact the outcomes presented in the ISP.

The ISP determined an optimal split of new solar and wind VRE that would minimise the need for dispatchable storage and generation and therefore keep costs down for consumers. This optimal split is shown in Figure 12 as approximately 43% solar and 57% wind by 2040 for the Central scenario. If DER is also included, the split is more balanced, with grid-scale or distributed solar expected to provide 61% of total new renewable energy capacity.

Figure 12 New NEM VRE build, solar (left) and wind (middle) and Central scenario split (right)



C2.2 Locating new variable renewable energy generation in renewable energy zones

There are benefits in developing the very large amounts of anticipated new generation, predominantly VRE, in designated areas known as REZs. The ideal near-term REZ locations should aim to take advantage of areas with attractive renewable resources and strong network with spare capacity and system strength. There are areas in the NEM which can support large amounts of VRE with little additional investment (REZ hosting capabilities are detailed in Appendix 5). Developing VRE generation in these REZs will normally be cheaper than building additional major network infrastructure to unlock a new REZ.

If well located, REZs can materially reduce total system and transition costs. They can:

- reduce the need to build transmission into new areas
- reduce project connection costs and risks
- optimise the mix of generation, storage and transmission investment across multiple connecting parties
- co-locate and optimise the otherwise 'lumpy' investments in network and system support infrastructure
- co-locate and optimise weather observation stations to improve real-time forecasting
- realise benefits of capital scale in all those investments
- promote regional expertise and employment at scale, and
- create investable, low risk opportunities for the private sector to invest in Australia's energy system.

The ISP has considered 35 possible candidates for REZs based on initial assessments of their resource, technical and economic parameters: see Figure 13. These were an input to the modelling for assessment of potential ISP development paths, resulting in a final set of REZs that are part of the optimal development path.

Co-optimisation of network augmentation and REZ development

Developments clustered in REZs are assessed from a broad range of factors and are co-optimised with other generation and transmission investment decisions in ISP market modelling. This captures the economic benefits of co-locating wind, solar and storage resources near existing or new interconnector corridors, and recognises the value of diversity and correlation with demand.

The factors consider how new and existing transmission and the emerging REZs can provide reliability and security, minimise environmental impacts, adhere to relevant design standards and regulatory requirements, and offer flexibility and expandability to address the future needs of the power system.

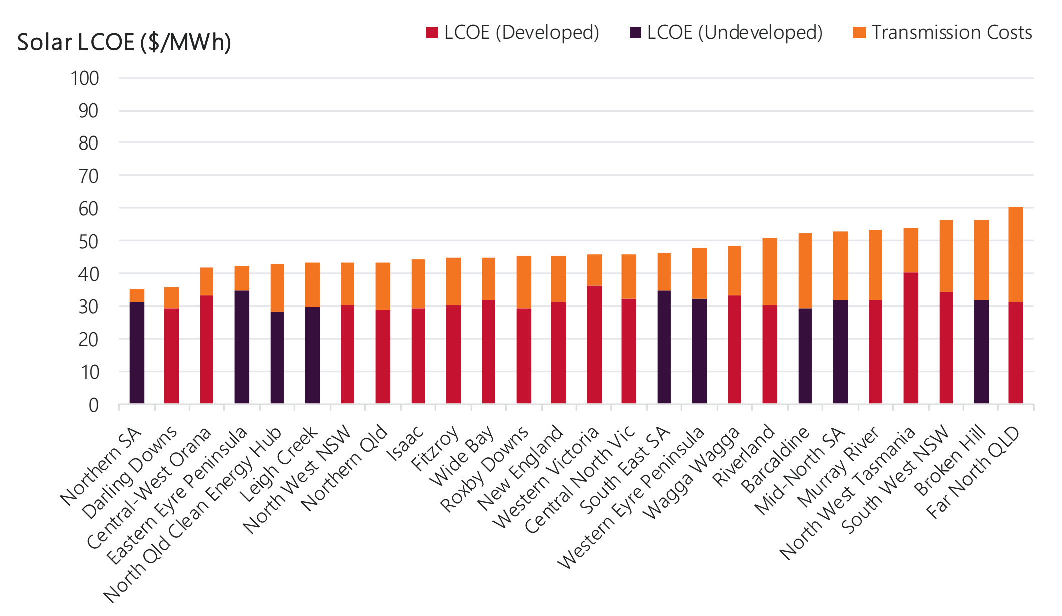
This co-optimisation process is detailed in Appendix 9 and in the ISP modelling methodology[34]. The result is the phased development of the REZs (see below), and the need for future ISP projects to support them (see Section E3: network investments in the optimal development path).

The levelised cost of electricity (LCOE) offers an approximate comparative view of the quality of REZs: see Box 4. However, AEMO stresses that the ISP analysis does not use LCOE to develop REZs, instead using the ISP's sophisticated integrated modelling that co-optimises generation and transmission build to maximise the value of REZ integration.

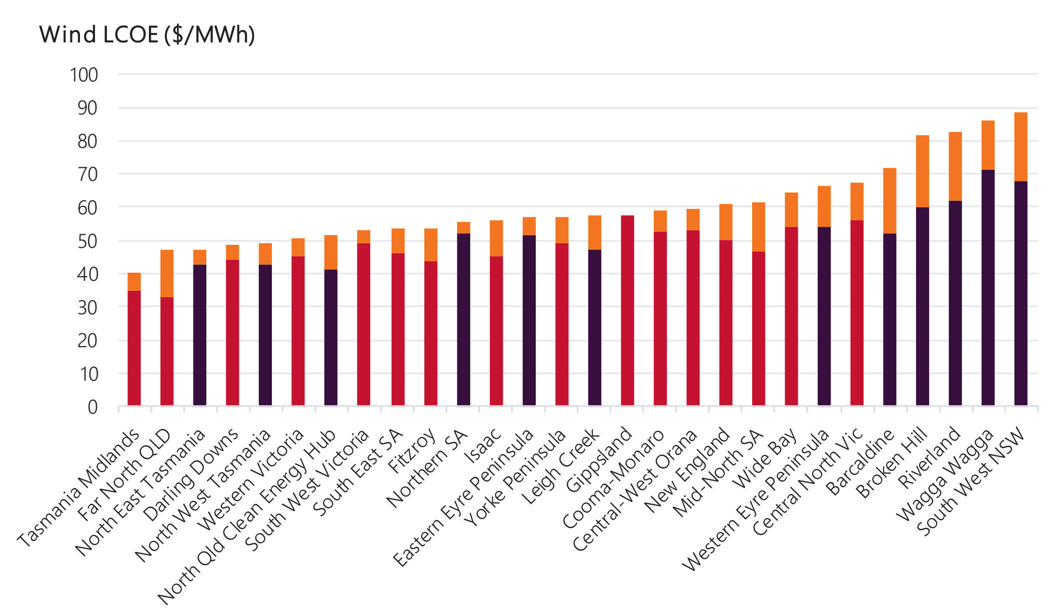
Box 4: Levelised cost of electricity for REZ (LCOE)

The ISP is underpinned by complex integrated modelling that co-optimises generation and transmission build to maximise the value of REZ integration. However, it is sometimes difficult to unpack the modelling 'black box' to understand why particular development options are preferred.

To assist, and for ISP reporting purposes only, the two figures below provide a high-level analysis of the 2040 LCOE for the various REZs.



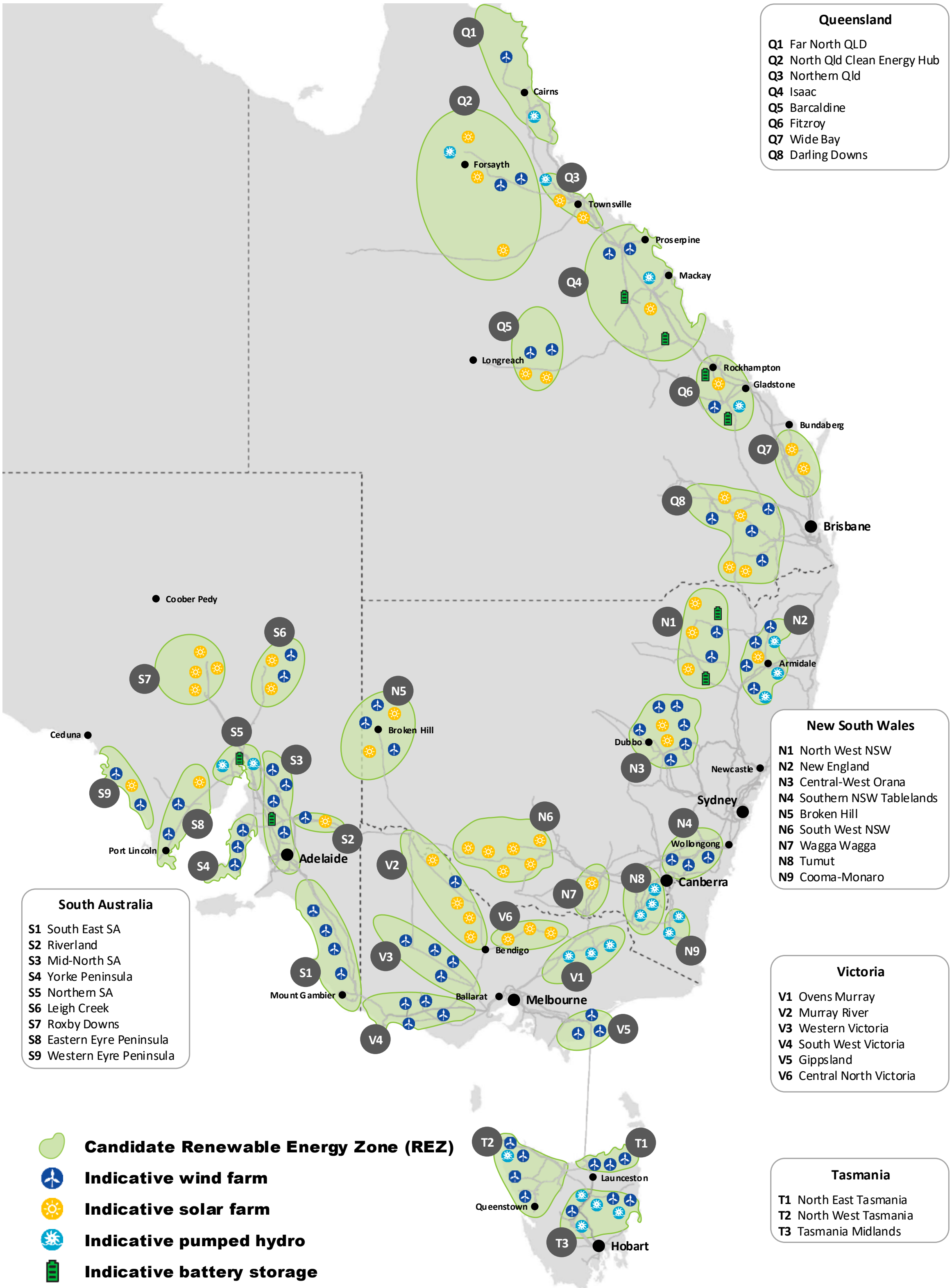
34 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp



This analysis focuses on the build and operating cost, the quality of the local resource, and likely REZ-specific network augmentation costs required to deliver REZ generation to the grid, but does not consider deeper network congestion that may limit the value of this generation to end consumers, and network requirements are very approximately estimated.

As a result, care should be taken when interpreting these LCOE values, as they do not accurately represent the power system requirements and can be optimistic or even misleading. The figures also indicate which of these REZs have been identified in the ISP as potential areas for REZ development (red columns) with potentially high value. Many of the REZs selected are also those with relatively low LCOEs, although in some cases (for example, Tasmania), the REZs are low cost but deliver limited market benefits without greater interconnection to load centres.

Figure 13 Identified candidate Renewable Energy Zones (REZs) for assessment in developing the optimal development path in the NEM



Phased development of Renewable Energy Zones

The resulting development opportunities for REZs in the optimal development path are described in Table 5 below. There are three overlapping development phases:

- **Phase 1:** Development to help meet regional energy targets (RETs) and other policies, and/or where there is good access to existing network capacity with good system strength.
- **Phase 2:** Renewable generation development to replace energy provided by retiring coal-fired generators and supported by the actionable ISP projects
- **Phase 3:** Renewable generation development to accompany future ISP projects that are being developed specifically to support them.

These REZs and their timing are based on actionable ISP projects in the optimal development path satisfying decision rules and being delivered in accordance with the optimal development path. For actionable ISP projects with decision rules, the REZ developments and phasing assumes that the decision rules are met, and the ISP projects are completed at the earliest timing. The optimal timing for the development of REZs and associated transmission is outlined in Table 5, with detailed information on each REZ and the assessments undertaken in Appendix 5.

Table 5 REZ developments

Phases of REZ development	Region	Description
Phase 1 **Connecting renewables to support government policy**	Queensland	VRE development primarily in Darling Downs (wind and solar) and Fitzroy REZs (wind and solar) taking advantage of the existing spare network capacity to meet the QRET.
	New South Wales	VRE development in Central-West Orana REZ (wind and solar) enabled by the Central-West Orana REZ Transmission Link, forming part of the NSW Electricity Strategy.
	Victoria	VRE development in Western Victoria REZ (wind) to help meet VRET and supported by the committed Western Victoria Transmission Network Project. VRE development in South West Victoria REZ (wind) and Central North Victoria REZ (wind and solar), taking advantage of the spare network capacity to meet the VRET.
	Tasmania	The development of VRE in Midlands, North East Tasmania and North West to meet the TRET.†
Phase 2 **Connecting renewables in areas supported by actionable ISP projects**	New South Wales	VRE development in South West NSW REZ (solar) is supported by Project EnergyConnect and VNI West (Kerang route)†, and Wagga Wagga REZ (solar) is supported by HumeLink. Pumped hydro generation in Tumut REZ is supported by the development of HumeLink.
	Victoria	Either development of VRE in Central North Victoria REZ supported by VNI West (Shepparton route), or Murray REZ supported by VNI West (Kerang route)†. VRE development in Western Victoria REZ is also supported by VNI West (either Kerang or Shepparton routes). Development of solar in Murray River REZ near Red Cliffs is supported by Project EnergyConnect.
	South Australia	The development of solar in the Riverland REZ enabled by Project EnergyConnect.
	Tasmania	The development of wind generation in the Midlands REZ which is supported by Marinus Link†.

Phases of REZ development	Region	Description
Phase 3 **Connecting renewables in areas supported by future ISP projects**	Queensland	VRE development in Darling Downs REZ (wind and solar) is supported by expansions of QNI in 2032-33 and 2035-36. Larger VRE development in Fitzroy REZ (wind and solar) and Isaac REZ (wind) are supported by future ISP projects, Gladstone Grid Reinforcement and Central to Southern Queensland transmission project. Developments in Far North Queensland REZ require upgrades within this REZ to connect renewable generation. Additional strengthening of the 275 kV network is also required.
	New South Wales	VRE development of solar in North West NSW REZ supported by expansions of QNI in 2032-33 and 2035-36. Large developments of wind in New England would require support from a future ISP project to augment the transmission system from the REZ to provide stronger access to supply the Greater Sydney region.
	South Australia	VRE development in Roxby Downs REZ (solar) and Mid-North REZ (wind) are supported by network upgrades between Davenport and Para. Development of wind in South East SA REZ requires the support of a future ISP project to connect generation within the REZ.

† The REZs and timing are based on actionable ISP projects in the optimal development path satisfying decision rules and being delivered in accordance with the optimal development path.

C3 6-19 GW of new dispatchable resources are needed to back up renewables by 2040

Depending on the scenario, the NEM will need 6-19 GW of new flexible, utility-scale dispatchable resources to firm up the inherently variable resources. This will be supported by innovative power system services: see Section C4 below.

Most initial investment will be in utility-scale pumped hydro (such as Snowy 2.0, already committed) or battery storage (assuming technology costs continue to fall, and the market arrangements sufficiently incentivise this development). Some distributed batteries are assumed to participate in the NEM and operate as a VPP, with this portion varying by scenario. DSP is also assumed to increase at different levels across scenarios, to help manage costs for consumers. New flexible gas generators could play a greater role if gas prices materially reduce. Ultimately, the NEM will draw on a technologically diverse mix that may diversify further as other technologies, such as hydrogen, mature. In the end, a well-designed market is best positioned to determine the optimal mix of these dispatchable resources as technological, economic and policy decision factors evolve over time.

C3.1 Dispatchable storage

Utility-scale energy storage can shift the timing of renewable energy production, reduce the magnitude of new intra-regional transmission required, and provide firming support during peak loads or when renewable production is low. The 2020 ISP analysis assumes optimal operation of the installed storage with perfect foresight. However, even minor inefficiencies in real world operations would lead to the need for more storage or other forms of dispatchable generation, to ensure reliable supply for consumers.

The growth in storage is broadly aligned with timing of coal-fired generation retirements. The type and depth of storage required (see Box 5) will depend on the mix and location of renewable generation, and the ability of existing generators to smooth out short-term and seasonal renewable variability themselves.

Box 5: Three depths of storage

In the ISP, AEMO has defined these dispatchable storage depth classes as:

- **Shallow storage for capacity, ramping and FCAS** – includes VPP battery and 2-hour large-scale batteries. This category of storage is more for capacity, fast ramping, and FCAS than it is for its energy value.
- **Medium storage for intra-day shifting** – includes 4-hour batteries, 6-hour pumped hydro, 12-hour pumped hydro, and the existing pumped hydro stations, Shoalhaven and Wivenhoe. The value of this category of storage is in its intra-day shifting capability, driven by demand and solar cycles.
- **Deep storage for VRE 'droughts' and seasonal smoothing** – includes 24-hour pumped hydro and 48-hour pumped hydro and includes Snowy 2.0 and Tumut 3. The value of this category of storage is in covering VRE 'droughts' (that is, long periods of lower-than-expected VRE availability), and seasonal smoothing of energy over weeks or months: see Figure 16.

Figure 14 highlights the mix of storage durations or dispatchable power that will be required to firm the growing share of renewable supply as existing thermal capacity exits. Initially, relatively shallow 1- to 2-hour storage is needed to provide firming capacity and intra-day energy shifting. However, as more coal-fired generation retires, medium 4- to 12-hour storage comes into play to shift energy over longer time scales. (The dark blue bands of deep pumped hydro represent Snowy 2.0 and other committed projects, so are constant throughout.)

Figure 14 Mix of dispatchable storage durations selected to firm renewables

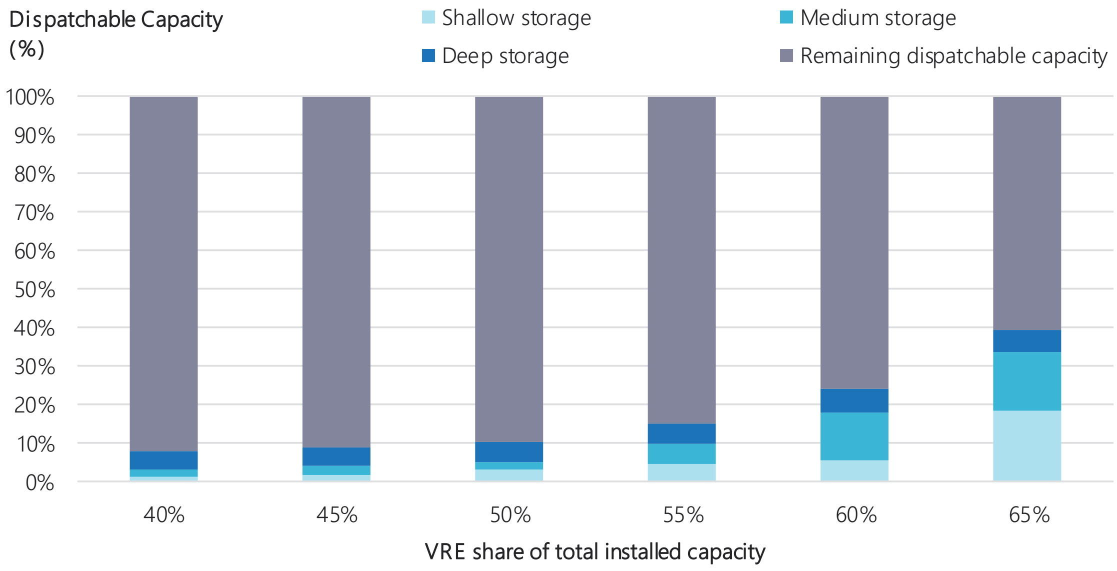
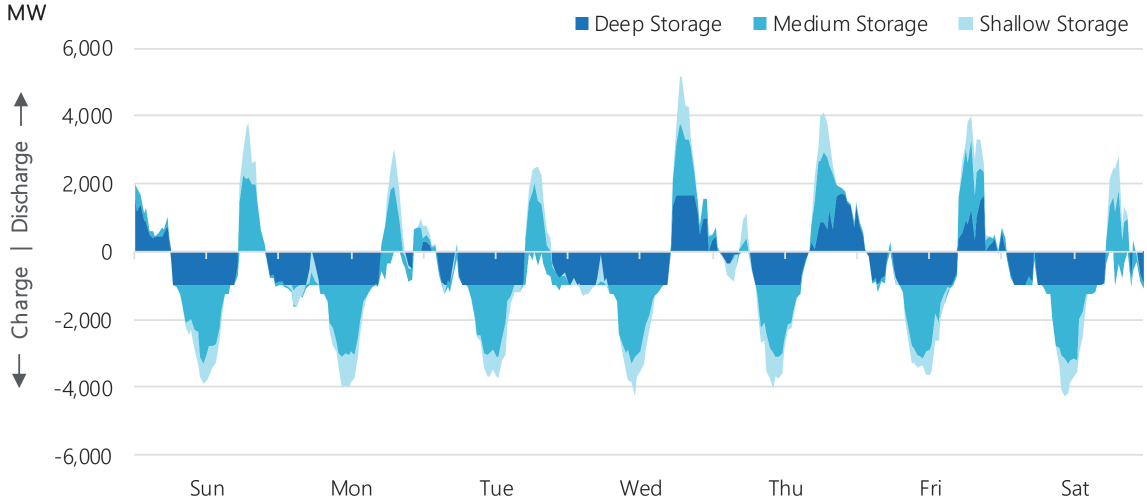


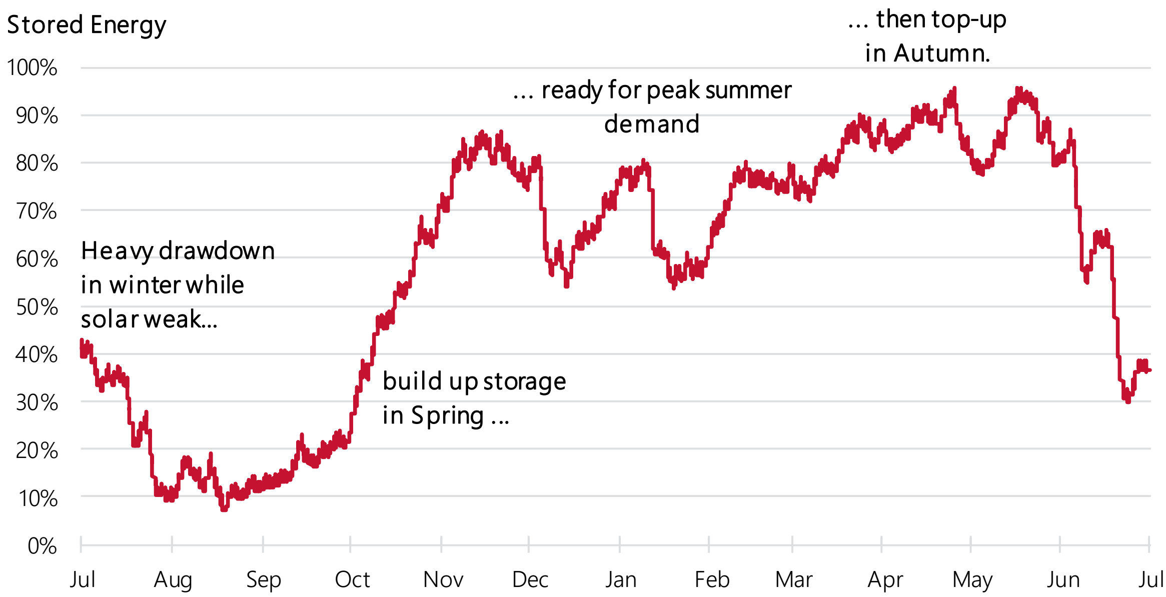
Figure 15 shows how the NEM's suite of storage types would operate for a week in Spring 2035 in the Central scenario, when the VRE share of total installed capacity is 56%. They act predominantly as intra-day energy shifters: absorbing excess energy from VRE in the middle of the day and releasing it during the evening peaks.

Figure 15 Indicative dispatchable storage operation in Spring 2034-35, Central scenario



Spring is a shoulder season with modest energy demand, when good renewable availability charges upper-level deep storages like Snowy 2.0 more than they discharge: see Figure 16 below. This energy is then ready for summer months, when deep storage can cover for peak demand periods by generating continuously for over 24 hours at a time. Then, after being topped up in the autumn shoulder season, deep storage can generate for several days without recharging in the winter months when solar generation is relatively low.

Figure 16 Deep storage balances energy loads throughout the year, 2034-35



C3.2 Gas-powered generation

GPG can provide the synchronous generation needed to balance variable renewable supply, and so is a potential complement to storage. The ultimate mix will depend upon the relative cost and availability of different storage technologies compared to future gas prices. This favours existing GPG plants, but further investment in GPG is less likely based on the assumptions used in this ISP, particularly in scenarios that have carbon budgets to meet.

Existing GPG plants will continue to play a critically important role in the NEM

The ISP modelling shows that GPG production is initially forecast to decline once Project EnergyConnect is built, as the interconnector allows greater sharing of VRE and coal-fired generation resources not otherwise fully utilised. However, as more coal-fired generation retires, and is replaced by VRE, production from existing GPG is forecast to rise again. It will then be more cost-effective to increase generation from existing GPG to compensate for low-renewable conditions than to invest in new deeper storages.

Existing combined-cycle gas turbines (CCGTs) and open-cycle gas turbines (OCGTs) are forecast to play critical complementary roles when significant coal generation retires in the 2030s:

- CCGTs, to provide longer-term firming (overnight, or during week-long wind-droughts)
- OCGTs, to cover summer peak demand periods or periods when unfortunate coincidences of generation outages or weather patterns reduce available supply, and
- in key power system service roles to provide grid security and stability (see Section C4).

The need for GPG is shown in the matrix of charts in Figure 17 below, which show modelled weeks of low and high VRE supply, and low and high energy demand:

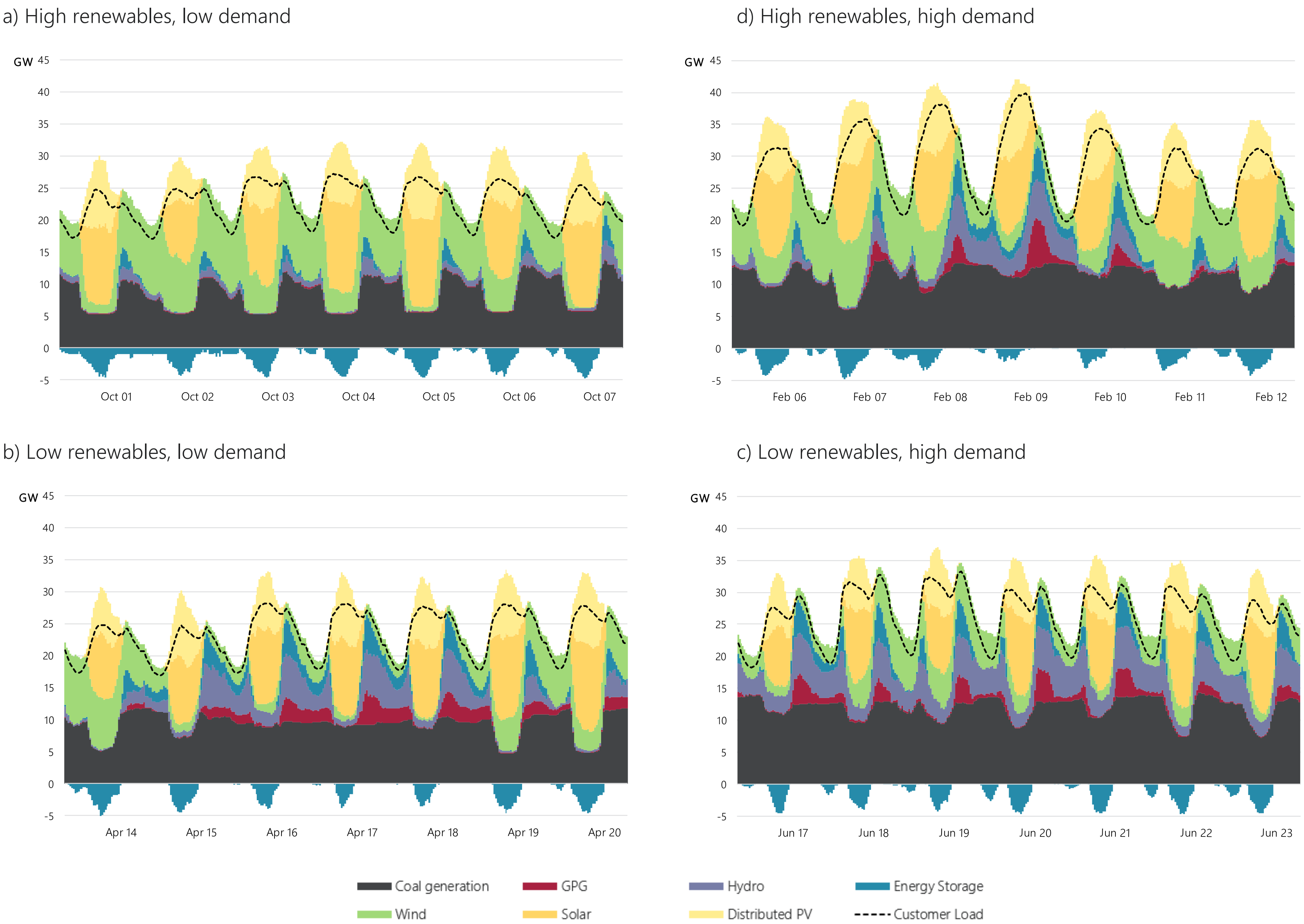
(a) In weeks with high renewable output and low demand, VRE output is well in excess of total demand, and GPG is barely needed. Coal generation effectively two-shifts, dropping generation as much as possible during the day when solar generation is highest, and deep storages filling their reservoirs from the excess energy.

(b) In weeks with high renewable output and high demand, GPG is needed to meet the demand peaks just after sunset, and to keep going through the night to cover shallow storages that may not have had an opportunity to fully charge during the day.

(c) In weeks of relatively still wind conditions and high demand, the system relies more on hydro (including Snowy 2.0) and coal, complemented in the evening peak by shallow storage (including VPP) charged from solar during the day. CCGTs assist throughout the night in these low VRE weeks, with peaking OCGT plants are required in the evening and occasionally the morning peaks.

(d) In weeks of low demand and low renewable output, CCGT is needed even more needed through the night, particularly during shoulder seasons such as autumn, when coal availability is reduced due to planned maintenance.

Figure 17 Indicative generation mix in the NEM, GW, 2035



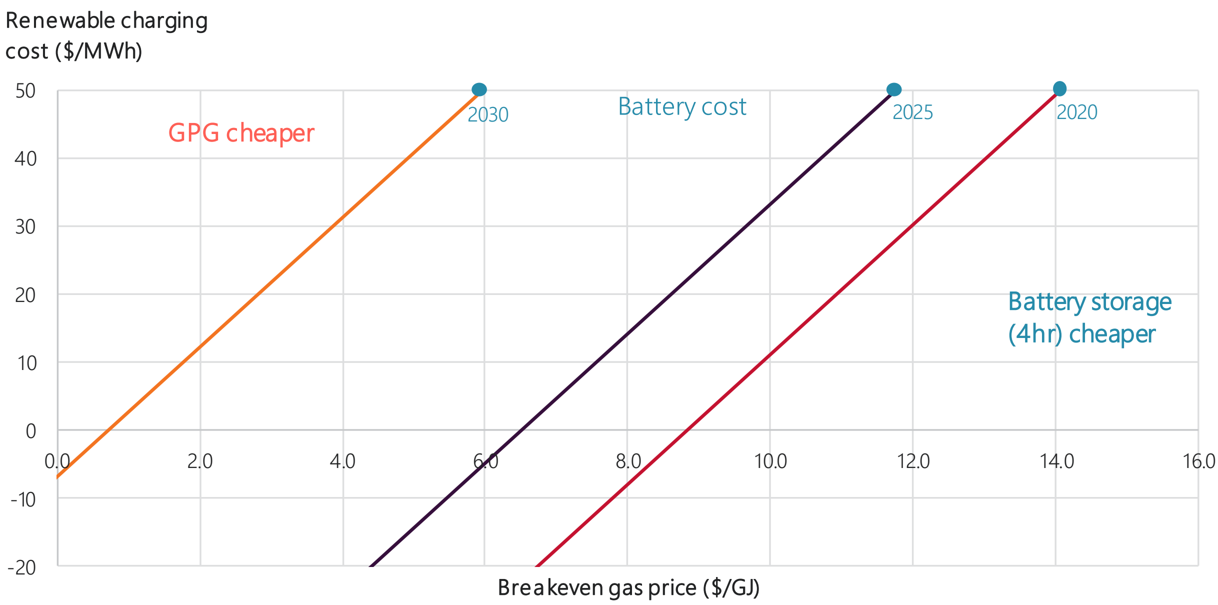
The investment case for new GPG will critically depend on future gas prices

GPG and batteries can both serve the daily peaking role that will be needed as VRE replaces coal-fired generation, so relative whole of life cost is a key variable for potential investors to consider. GPG has a cost advantage over batteries at current gas and battery costs. However, in the 2030s when significant investment in new dispatchable capacity is needed, this advantage could shift to batteries, especially to provide dispatchable supply during 2- and 4-hour periods. Based on the cost assumptions in the ISP, new batteries are more cost-effective than GPG in the 2030s. Future climate policies may also impact the investment case for new GPG.

That said, it is difficult to accurately forecast future fuel and technology costs. For example, a new policy initiative could aim to significantly reduce gas prices or maintain current low prices well into the future. Such a policy intervention could shift the balance of investments between batteries (or pumped hydro) and new GPG.

Figure 18 below shows a sensitivity analysis to ascertain the impact of different future long-term average gas prices on battery and GPG investments. It depicts the breakeven cost between batteries and GPG to provide a daily 4-hour dispatchable supply as a function of long-term average gas price and the long-term average cost to re-charge a battery. Batteries are typically re-charged in the middle of the day, when even today prices already reach $0/MWh or even negative prices at times. The diagonal breakeven lines for a gas vs battery investment move from the right (today) to left (2030). At today's relatively low gas prices, a 4-hour battery installed today (at $1,964 /kW capital cost) would need to be charged for free to be competitive with a new OCGT (at $1,416 /kW). However, for GPG to remain a competitive investment as battery costs reduce (to $922/kW by 2030), gas prices need to be as low as $4/GJ in the long run, while charging costs need to remain relatively high at $30/MWh. Even in 2019-20, 4-hour batteries would have been able to charge at an average price below $30/MWh in all regions except New South Wales.

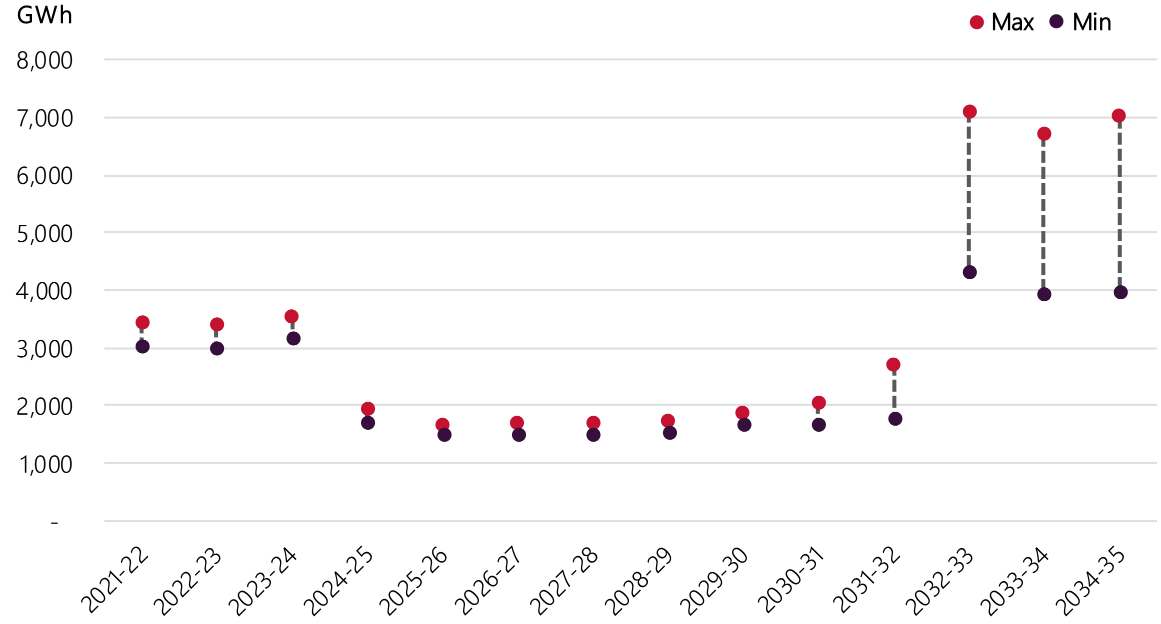
Figure 18 Breakeven cost analysis – new GPG versus battery capacity for providing daily peaking support



Potential investors in GPG would also have to take into account how the variability of gas consumption is likely to rise. Gas consumption is influenced by climate and weather events such as extreme temperatures or droughts, which are more likely as climate change continues, and prolonged thermal generation outages. This variability is compounded as coal retires and VRE penetration increases.

Figure 19 below shows how the energy produced by GPG may increase after significant coal retires post-2032, but that the variability of GPG across different weather reference years becomes much more volatile[35]. Note that this analysis has been prepared to show the potential variability of gas demand. The absolute values of gas generation in this chart are lower than currently observed in the market. This is because they have been derived by minimising total system cost, which optimally uses all available resources. In practice, exceptional events (such as the recent islanding of South Australia), AEMO directions to maintain system security, contract positions and strategic bidding by generators can increase the level of gas usage by GPG and increase costs to consumers.

Figure 19 Projected GPG generation across a range of reference years



Future scarcity of gas supply

Confidence in GPG as an investable and dispatchable energy resource also depends on there being reliable, affordable gas fuel. Yet gas supplies are already tightening in Australia, with southern supply from existing and committed gas developments forecast to reduce by more than 35% over the next five years[36]. After gas fields cease production between mid-2023 and mid-2024, gas supply restrictions and curtailment of GPG may be necessary, particularly during peak winter days.

To avoid this, southern Australia will need to either develop new local sources (and pipeline infrastructure), progress liquified natural gas (LNG) import terminals or address pipeline limitations from northern Australia. ISP modelling forecasts approximately 120 PJ to 285 PJ of additional gas will be needed each year between 2024-25 and 2036-37 to meet residential, commercial and industrial gas demand, gas for LNG

[35] This analysis is based on short-run marginal cost bidding and is therefore a lower bound on likely GPG demand, but the trends are relevant to demonstrate the change role and annual variability of gas demand. For more realistic GPG outcomes, see Appendix 6.

[36] AEMO 2020, Gas Statement of Opportunities (GSOO)

export, and gas supply for GPG: see Figure 20. To ensure this level of supply, let alone enable a greater reliance on gas, a policy intervention may be required. From that point, major Queensland reserves are projected to decline and would need to be replaced with another 1,000 PJ of currently contingent or prospective resources.

Figure 20 New gas supplies required each year, under Central scenario

Stronger interconnection between NEM regions reduces reliance on GPG, more so during drought conditions, as alternative resources can be shared more effectively to compensate for reductions in hydro generation. By smoothing weather-driven variances in GPG demand, interconnectors help mitigate the risk of gas supply disruptions or shortfalls, and ultimately help keep costs down for consumers

C3.3 Demand side participation

DSP is the voluntary reduction or shift of electricity use from the grid by consumers, in response to high prices or network reliability events. It enables the operator to aggregate these responses to meet the needs of the system, and so ensure available supply can meet demand and that prices are moderated. The response is typically orchestrated by network companies, retailers or specialist DSP aggregators who trigger load reductions or embedded generation at participating customers.

DSP across the NEM is forecast to double by 2040 in the Central scenario (and quadruple in the Step Change scenario). This forecast growth is driven by advances in information and control technology and by market reforms. Behind-the-meter battery storage (VPP) and charging of EVs will also add significant extra controllable demand across the NEM. These resources are changing the nature of demand side service offerings – with demand following supply rather than the other way.

These two-sided markets will not only need to be designed for peak shaving services but address other flexibility requirements – minimum demand, load shifting and load shaping to name a few.

C4 System services critical to enable the transition

Innovative system services that provide essential system security requirements are needed to transform a system that has relied on thermal synchronous generation in the past to provide these services. As very large amounts of inverter-based resources (IBR) are projected from the mid-2020s, most new VRE developments utilising current inverter technology are likely to need to be complemented by some form of system strength remediation from the mid-2020s (this does not necessarily mean synchronous condensers, as new IBR could provide some of the system services requirements as part of their design, if market arrangements provide incentives for these investments).

There are already examples of the increasing need for system services as more IBR is installed and existing synchronous machines exit:

- In **South Australia,** AEMO declared inertia and fault level shortfalls in 2018, which ElectraNet is now addressing, mainly by installing major high-inertia synchronous condensers. These are needed immediately and remain valuable after the recommended Project EnergyConnect interconnector between South Australia and New South Wales is completed.
- In **Tasmania**, AEMO declared inertia and fault-level shortfalls in November 2019, for which TasNetworks has procured a solution.
- In **Victoria**, AEMO declared a fault-level shortfall in north west Victoria in December 2019, for which AEMO Victorian Planning is developing a solution..
- In **Queensland**, AEMO declared a fault-level shortfall in north Queensland in April 2020, for which Powerlink has developed an interim solution.

A coordinated approach to the network and system services for REZs can provide efficiencies of scale and lower costs for the required network and system security services than if adopting a project-by-project approach. Appendix 7 sets out in detail the key security needs to 2030.

The optimal development path laid out in this ISP will only optimise consumer benefits as long as regulatory and market reforms are completed to realise the projected investments in generation, storage and other essential system services. The industry's work to prepare the NEM and its regulations for an even more complex and diverse energy system must continue at pace.

C5 Market reforms are essential to support the ISP development opportunities

The need for market reform to support the technical integration of DER is discussed in Section C1.2 above. That is just the start of a broad suite of market reforms that will be needed if the ISP development opportunities are to play their role in the ISP's optimal development path. Consumer benefits will only be realised if market arrangements encourage the optimal use of existing resources and give appropriate signals for further investment.

- The market will need to incentivise timely investment in essential services and resources needed to replace retiring generators. Without managed exit and entry of resources, consumers would be exposed to higher costs as they have been following every single generator exit in the NEM over the past decade. For dispatchable resources, market design must not only recognise the provision of energy, but also the increasing value of flexibility and dispatchability in complementing and firming intermittent generation, and other system security services currently provided by generators which are scheduled to soon retire. For example, an investor in new pumped hydro could build the plant with the capability to provide system strength and inertia, even when it does not need to produce energy.
- Being able to provide these services with zero megawatts and zero fuel costs is increasingly valuable at very high penetrations of IBR. Yet unless the necessary market reforms are in place, necessary resources

may not be delivered on time and the system will have to rely on other mechanisms – for instance transmission investment – to compensate for the lack of adequate resources.

Operationally, the NEM's real-time market can be complemented by arrangements that give greater visibility of available resources and options. This would ensure resource sufficiency, including day ahead markets, and that the right resources are available at the right time and can be co-optimised to reduce their cost. Managing operations ahead of time can also minimise operational risk and revenue uncertainty for market participants. For example, a paper mill may adjust its electricity demand if it has some notice period and pricing can be locked in to reward the adjustment.

The ESB's market reform program is considering many such market and regulatory framework options: their expected benefits, costs and other trade-offs[37].

[37] See ESB's information of its post 2025 market design program at http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board

Part D

ISP network projects and their development paths

Part C set out the energy resources the NEM will need over the next 20 years to deliver low-cost, reliable and secure energy to consumers across a range of future scenarios. It confirms that generation in the NEM will evolve from centralised coal-fired generation to a diverse portfolio dominated by DER and VRE, supported by dispatchable resources, with enhanced power system service capabilities.

These diverse energy resources will depend for their efficient, reliable and secure use on a NEM network that is a true, interconnected energy highway. VRE in particular is spread far across the eastern states, to take advantage of geographic weather diversity, and so requires a greater network footprint than conventional coal-fired generation. If the VRE is coordinated with strategic investments in the transmission network, the greater resource diversity and competition will reduce the costs of supply. This in turn should result in downward pressure on electricity bills, assuming effective wholesale and retail markets.

This Part D presents the projects needed to augment the NEM network over the next 20 years if it is to meet that purpose. The possible sets of projects and their timing are "candidate development paths", and the optimal development path is the one that optimises net market benefits while meeting power system reliability, security and public policy needs. The optimal development path in particular achieves positive net market benefits under the Central scenario[38] and minimises regrets across the other scenarios and sensitivities[39].

Part D narrows the field of those development paths by identifying:

1. The targeted grid augmentations needed to balance resources and unlock Renewable Energy Zones
2. The eight candidate development paths that best deliver power system requirements and economic benefits, and
3. The candidate development path(s) that perform best under two forms of cost-benefit analysis.

   Part E then selects the optimal development path from those candidates.

D1 Targeted grid augmentation to balance resources and unlock Renewable Energy Zones

Applying economic and power system modelling to a large range of possible options, the ISP has selected 18 network projects needed to support Australia's energy resources through to 2040. These projects are commercially and technically feasible, and represent the full range of possible transmission combinations:

- three ISP projects that are already committed

[38] Clauses 5.22.5(e)(3 and 5.22.6(a)(4) of the NER

[39] Chosen by AEMO as the best method to select the optimal development path under R.22.5 (e)(2)

- six projects to strengthen transmission flow paths between Queensland, New South Wales, Victoria, South Australia and Tasmania – to complete a true inter-regional NEM, and
- nine future grid expansions to accompany the timely development of REZs and relieve network congestion[40].

The details of all 18 projects and the considered options are set out in Appendix 3.

D1.1 Committed network projects

Three projects have become committed since the 2018 ISP and are included in all candidate development paths as well as the counterfactual in this ISP:

- **South Australia system strength remediation:** the installation of four high-inertia synchronous condensers as recommended in the 2018 ISP, urgently needed to supply the necessary system strength required to operate the South Australia power system securely
- **Western Victoria Transmission Network Project:** new 220 kV and 500 kV double-circuit lines to add transmission to the western and north-western Victoria REZs, unlocking renewable energy resources, reducing congestion and improving the productivity of existing assets, and
- **QNI Minor:** a minor upgrade of the existing interconnector, to increase Queensland transfer capacity to New South Wales by 190 MW and increase New South Wales transfer capacity to Queensland by 460 MW.

D1.2 Potential upgrades to national transmission flow paths

Major network investments beyond what is currently committed will also be needed by 2040, to strengthen the NEM and deliver the significant resources and market benefits discussed in Parts B and C.

Six major transmission projects have been selected from a large range of credible options and combinations to determine the mix of investments that optimise consumer benefit: see Appendix 3 for full details of options considered.

The network options AEMO has assessed as having the most merit are:

- **VNI Minor**[41]: a minor upgrade to the existing Victoria – New South Wales interconnector, recommended as urgent in the 2018 ISP and confirmed as no-regret in this ISP.
- **Project EnergyConnect**[42]: a new 330 kV double-circuit interconnector to increase transfer capacity between South Australia and New South Wales by 750 MW, deliver fuel cost savings and unlock already stranded renewable investments. Recommended in the 2018 ISP and confirmed as low regret in this ISP.
- **HumeLink**[43]: a 500 kV transmission upgrade to reinforce the New South Wales southern shared network to increase transfer capacity to the region's demand centres in combination with Project

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[40] These are future projects needed to increase hosting capacity of REZ but for which discrete project options are yet to be identified. Preparatory activities will be required to better inform future ISPs

[41] https://www.aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-upgrade-regulatory-investment-test-for-transmission

[42] https://www.projectenergyconnect.com.au/

[43] https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network

EnergyConnect. New single circuits between Maragle, Bannaby and Wagga Wagga and associated works, recommended in the 2018 ISP, and confirmed as low regret in this ISP.

- **Central-West Orana REZ Transmission Link**[44]: a 500 kV (or 330kV) loop which traverses the Central-West region and is assumed to commence construction in 2022 to unlock up to 3,000 MW of new VRE by the mid-2020s as part of the New South Wales Transmission Infrastructure Strategy. The transmission line is estimated to cost $675 million and is treated in this ISP as a 'no regret' investment option for consumers because the New South Wales and Commonwealth governments have committed to cover any costs in excess of benefits determined at the RIT-T stage. This is outlined in the Memorandum of Understanding between the Commonwealth and New South Wales governments, dated 31 January 2020, to provide financial support to this project if required[45].
- **VNI West[46], connecting Victoria with New South Wales and Snowy 2.0:** the ISP clearly demonstrates the need for and benefits of a major new interconnection between New South Wales and Victoria in all scenarios except Slow Change and High DER. The connection with Snowy 2.0 will give Victoria much needed dispatchable capacity, to maintain reliability as more coal-fired generation retires and help to alleviate constraints on VRE in the north west or central areas of Victoria. It also helps share VRE in Victoria and Tasmania with the northern regions of the NEM, reducing heavy ramping duty otherwise expected on aging brown coal generation assets that were designed for baseload operation. The optimal timing of VNI West is discussed in Section E1 below.
  - The ISP has considered a range of options for meeting the identified need: see Appendix 3. The outcome of this assessment is AEMO's recommendation on either of two preferred routes for VNI West – the choice between them depending on VRE development priorities in local areas.
  - The first route is from a new substation north of Ballarat directly to Wagga Wagga, running to the north of Bendigo and near Shepparton, and supporting Central North Victoria and Wagga Wagga REZs. The other route is from a new substation north of Ballarat to Dinawan via Kerang, supporting the Murray and South West New South Wales REZs.
- **Marinus Link, connecting Victoria with Tasmania:** Marinus Link is a second and potentially third HVDC cable interconnection across Bass Strait, each with a transfer capability of 750 MW in both directions. It would deliver net market benefits and support the energy market transition by accessing necessary large-scale and deep storage in Tasmania to increase network reliability, allowing more efficient generation sharing between Tasmania and Victoria, reducing generation dispatch costs, and adding 540 MW hosting capacity to the attractive wind resource of the Tasmania Midlands REZ. Marinus Link would be beneficial in all scenarios except Slow Change. If the Step Change scenario occurs, one cable would be needed as soon as possible for Tasmania's deep storage to store mainland VRE during the day and then release it back during peak demand periods. Marinus Link would also be essential to help achieve TRET, should it become legislated
- **Queensland – New South Wales Interconnection (Medium and Large QNI):** QNI Medium is a single 500 kV circuit strung on a double circuit tower in the western part of the existing QNI. The proposed route goes through the North West New South Wales and Darling Downs REZs. A second 500 kV circuit could then be strung on the same tower, to become QNI Large. The cables would export excess renewable generation from Queensland and share existing and future REZ generation more efficiently

[44] TransGrid. *Central-West Orana REZ Transmission Link*, at https://www.transgrid.com.au/centralwestorana

[45] https:/energy.nsw.gov.au/media/2001/

[46] There are a number of potential routes still being explored to serve this need.

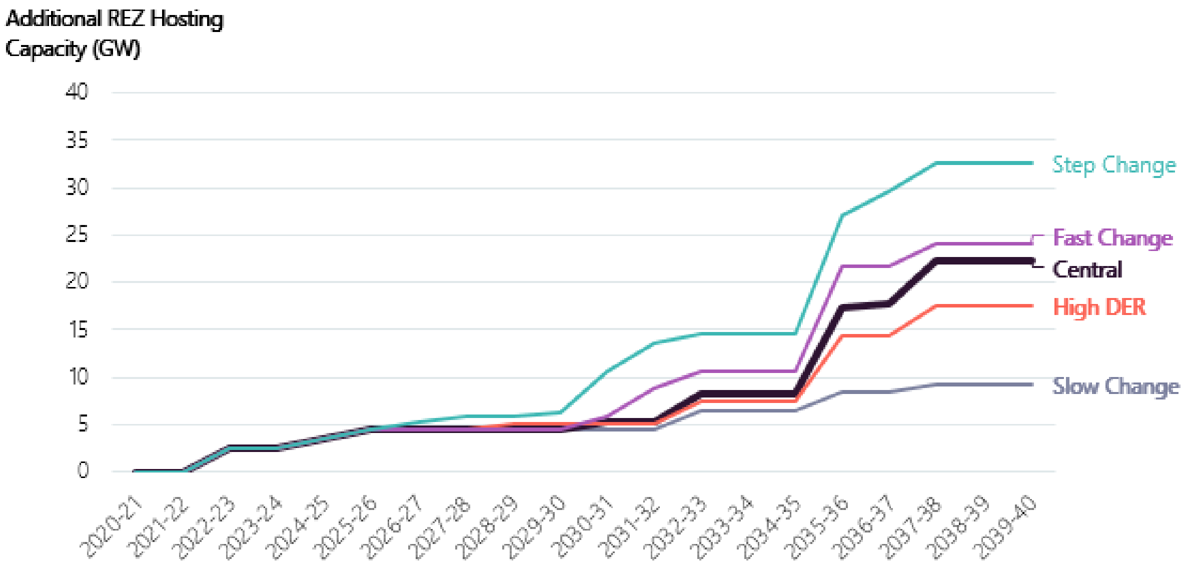
between regions as aging black coal-fired generators retire. The project is beneficial in all but the Slow Change scenario by no later than 2032-33, and must pre-empt the significant closures of New South Wales coal generators in the 2030s.

D1.3 Additional network augmentations to accompany the timely development of VRE

As discussed in Section C2.2, the design of REZs and the transmission network projects to support them is integrated with the other major interconnectors and intra-regional network augmentations. The national transmission upgrades listed above support large quantities of VRE in REZs, but more intra-regional network augmentations are also needed and are included in this ISP.

An indication of the additional connection capacity required in each scenario by 2040 is provided in Figure 21 and detailed in Appendices 3 and 5. This takes into account both residual capacity in the existing system and the additional capacity created by the ISP projects listed above. The timing and optimal location will depend on which scenario plays out, and the design and timing of the ISP projects in the optimal development path.

Figure 21 ISP projects in the least-cost scenario development paths will increase REZ hosting capacity



This capacity would be met partly by the ISP projects already listed above, and partly by eight further projects that would support the emerging REZs and address network congestion:

- **Three Queensland augmentations**, upgrading the network from Central to Southern Queensland, reinforcing the network around Gladstone, and augmenting the far north Queensland network.
- **Three New South Wales augmentations**, reinforcing supply to Sydney, Newcastle and Wollongong Supply, and augmenting the network around and south of New England and North West REZs.
- **Two South Australian augmentations**, to the south-east and the mid-north South Australian network.

The ISP projects (committed, actionable and future) in the optimal development path support REZ development by increasing REZ hosting capacity as they are completed.

D2 Projects combine as candidate development paths

Having identified the network augmentations that the NEM needs through to 2040, the ISP must determine when those projects should be completed to deliver the greatest net market benefits to consumers. AEMO has selected eight candidate development paths, being:

- the least-cost development paths for each of the five core scenarios, and
- three further candidates to test the option value of staging or accelerating VNI West and Marinus Link.

D2.1 Least-cost development paths for each scenario and sensitivity

The economic and power system analysis described in Part B identified the least-cost development paths for each of the original five core scenarios as those in Table 6 below.

Table 6 The ideal timing for transmission investment under the five core scenarios, based on least-cost development path

<table>
<tr><th>Network project
Scenario/ sensitivity</th><th>VNI Minor</th><th>Central-West Orana</th><th>Project Energy Connect</th><th>HumeLink</th><th>QNI Medium</th><th>QNI Large</th><th>VNI West</th><th>Marinus Link 1st Cable</th><th>Marinus Link 2nd Cable</th></tr>
<tr><td>Central</td><td rowspan="5">2022-23</td><td rowspan="5">2024-25</td><td>2024-25</td><td>2025-26</td><td>2032-33</td><td>2035-36</td><td>2035-36</td><td>2036-37</td><td>Not needed</td></tr>
<tr><td>Slow Change‡</td><td colspan="7">No further interconnections needed as this scenario delays the retirement of coal-fired generation and the need for replacement VRE</td></tr>
<tr><td>Fast Change</td><td rowspan="3">2024-25</td><td rowspan="2">2025-26</td><td rowspan="3">2032-33</td><td rowspan="3">2035-36</td><td rowspan="2">2035-36</td><td>2031-32</td><td>Not needed</td></tr>
<tr><td>Step Change</td><td>2028-29</td><td>2031-32</td></tr>
<tr><td>High DER</td><td>Not needed‡</td><td>Not needed</td><td>2031-32</td><td>2035-36</td></tr>
</table>

† While HumeLink and Project EnergyConnect are not part of the least-cost development path under the Slow Change scenario under current cost estimates, they are low-regret investments given the relatively low likelihood of this scenario and are therefore included in all candidate development paths.
‡ While HumeLink is not part of the least-cost development path under the High DER scenario under current cost estimates, the majority of the ISP analysis was performed based on a lower cost estimate that resulted in HumeLink still being part of the least cost development path for this scenario. Therefore, any reference to High DER least cost development path in remainder of report includes HumeLink.

However, in determining the optimal development path, the ISP must consider and compare potential investments that may be valuable under multiple future scenarios. For example, low-cost early development work can be taken without committing to the full project, or transmission lines can be designed as double circuit, but strung initially as single circuit. Investing early in this way, and being prepared for events such as an early plant closure, carries considerably less reliability risk and consumer costs than investing too late. With these cost-effective early investments, we have the option of accelerating development when consumers need us to. However, without creating such options, we might end up having no or only expensive responses available to manage unexpected events.

D2.2 Selection of candidate development paths

This philosophy informs the selection and assessment of "candidate development paths". The eight candidate development paths chosen for the ISP are set out in Table 7:

- **Candidates DP1 to DP5 are the least-cost development paths for each of the five core scenarios**[47]. These see the four low-regret projects already being progressed by TNSPs (VNI Minor, Project EnergyConnect, HumeLink and Central-West Orana REZ Transmission Link) completed by 2025-26 at the latest. The development paths then vary on the inclusion of QNI Medium and Large stages, VNI West, and the two cables of Marinus Link:
  - In the **Slow Change scenario**, the delay in coal-fired generation retirements and slower economic growth means that only the four low-regret interconnectors are required
  - The need for **QNI Medium** is linked to the retirement of black coal-fired power stations, particularly Eraring Power Station. In the Slow Change scenario, the refurbishment of Queensland (Gladstone) and New South Wales (Bayswater) coal generators defers the need for QNI Medium.
  - The need for **VNI West** decreases in scenarios with coal-fired generation refurbishments (as in Slow Change scenario) or large volumes of distributed batteries (as in High DER scenario).
  - **Marinus Link** timing is heavily influenced by emission abatement policies. The tighter the carbon budget, the earlier the first cable is built. Similarly, in scenarios where the announced TRET is assumed to be legislated, the first cable is built no later than 2031-32, with the second cable built three to four years later.
- **Candidates DP6 to DP8 test the option value of staging or accelerating VNI West and Marinus Link,** testing whether investing earlier in these projects would cost less over 20 years than investing too late. Each of the candidates DP6 to DP8 adds early works for Marinus link to the least-cost path of the Central scenario (DP1), allowing construction of the link to occur if and when required under each scenario. The variations for VNI West[48] are for delivery by 2035-36 (DP6), by 2027-28 (DP8) or allow early works for flexibility (DP7).

The projects and timings of each development path are held fixed across all scenarios and sensitivities, in line with the AER's draft CBA guidelines. If a project is staged, however, only the first stage is fixed across scenarios, with later stages being able to adapt as the future unfolds.

[47] There are differences in the composition and size of the supply side resources, depending on which scenario and which development path apply. The detailed modelling results are set out in the Generation and Transmission Outlook spreadsheets published in conjunction with the ISP.

[48] Only the option value associated with the VNI West (Shepparton) route has been evaluated in these candidate development paths as it is the lower cost of the two route alternatives. Similar benefits are expected to accrue for VNI West (Kerang).

Table 7 Candidate development paths, defined by timing of their common, major interconnection projects, based on least-cost development paths

<table>
<tr><th colspan="2">Development path</th><th>VNI Minor</th><th>Central-west Orana</th><th>Project Energy Connect</th><th>HumeLink</th><th>QNI medium and large</th><th>VNI West</th><th>Marinus Link Stage 1</th><th>Marinus Link Stage 2</th></tr>
<tr><td>1</td><td>Central least-cost</td><td rowspan="8">2022-23</td><td rowspan="8">2024-25</td><td rowspan="8">2024-25</td><td rowspan="8">2025-26</td><td>2032-33 and 2035-36</td><td>2035-36</td><td>2036-37</td><td>N/A</td></tr>
<tr><td>2</td><td>Slow low regret</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>3</td><td>Fast least-cost</td><td rowspan="6">2032-33 and 2035-36</td><td rowspan="2">2035-36</td><td>2031-32</td><td>N/A</td></tr>
<tr><td>4</td><td>Step least-cost</td><td>2028-29</td><td>2031-32</td></tr>
<tr><td>5</td><td>High DER least-cost</td><td>N/A</td><td>2031-32</td><td>2035-36</td></tr>
<tr><td>6</td><td>Central, early works ML</td><td>2035-36</td><td colspan="2">Variable†</td></tr>
<tr><td>7</td><td>Central, early works ML and VNI</td><td colspan="3">Variable†</td></tr>
<tr><td>8</td><td>Central, early works ML, accelerated VNI</td><td>2027-28</td><td colspan="2">Variable†</td></tr>
</table>

† Actual timing of these projects in each scenario under this candidate development path will be consistent with the least cost development timings listed in Table 6.

D2.3 Testing early or accelerated works for VNI West and Marinus Link

Candidate development paths DP6, DP7 and DP8 test the benefit of more flexible timing for VNI West and Marinus Link.

VNI West early development

The least-cost delivery timing for VNI West is 2035-36 in most ISP scenarios. accelerating investment provides additional option value under particular circumstances. Early works would enable the delivery of VNI West in 2027-28, with this option value assessed in candidate development path DP7.

The early works in this case includes all feasibility, design and approvals phases, and provides flexibility in timing of the subsequent construction phase. Initial estimates of the costs of these activities lie between $150-$200 million, and will be further refined in the RIT-T. However, since these activities are required whenever the project is completed, the true early works cost is simply the cost of bringing them forward. For example, the NPV in current dollars of bringing forward costs of $150 million would only be $52 million if VNI West is eventually built, and approximately $139 million if it is not (DP2 and DP5).

Candidate development path DP8 tests the value of building the full VNI West early under all scenarios, rather than using completion of early works as a decision gateway to reassess investment before proceeding through to construction. The investment is unlikely to be stranded, as in almost all scenarios VNI West is needed by the mid-2030s.

Marinus Link early works

The first Marinus Link cable (Stage 1) is needed in all ISP scenarios except Slow Change, but the optimal delivery timing ranges from 2028-29 to 2036-37. The second Marinus Link cable (Stage 2) is needed shortly after the first if TRET is legislated, with optimal delivery timing ranging from 2031-32 to 2035-36 (see Table 4). Early works on both stages would secure the option to deliver Marinus Link Stage 1 as early as 2028-29 if needed, and this early works staging has been included in candidate development paths DP6, DP7 and DP8. With the flexibility that early works brings, the optimal timing of the first and second cable under these candidate development paths is then varied depending on scenario, as per timings shown in Table 6.

The early works extend beyond preparatory activities to maximise optionality, without committing to the full project. They comprise all feasibility, design and approvals phases, including marine and land surveys, for both cables, to the point of being ready to commence construction. Early works on Marinus Link would be completed by a Final Investment Decision in 2023-24, to enable completion by 2028-29 if the Step Change scenario unfolds, 2031-32 if TRET is legislated or otherwise postpone it to 2036-37. Under any scenario, successful resolution on how the costs of the project will be recovered from consumers will be a precursor to development.

TasNetworks advises that completing the early works now would cost $140 million. Completing them in seven to ten years would be approximately $174 million, including the cost of any re-working. The time value of money reduces that $34 million gap to $20 million.

D3 CBA assessment of the candidate development paths

The ISP compares the eight candidates against the "counterfactual" development path – no future network development other than committed ISP projects or small intra-regional augmentations and replacements expenditure projects[49]. The NPV of each candidate is its cost-benefit compared with the counterfactual case.

Some candidate development paths will be beneficial to energy users in some scenarios and costly in others – but we do not know which scenario will eventuate. The AER's draft CBA Guidelines provide for a mandatory and, if needed, an alternate way to identify the development path that is most likely to deliver the expected benefits to consumers by quantifiable methods.

The two approaches are:

A. Find the candidate with the highest weighted-average benefit, with the weighting representing the relative likelihood of each scenario occurring (the mandatory 'scenario-weighted' approach), and

B. Find the candidate that minimises the risk of costly outcomes across the scenarios, in case the operating environment shifts from one scenario to another (AEMO's alternative 'least regrets' approach).

Candidate DP6 is the path suggested by applying both of the methods, that is:

- The four low-regret transmission projects (VNI Minor, Project EnergyConnect, HumeLink and Central-West Orana REZ Transmission Link) are completed by 2025-26 at the latest.
- Marinus Link early works progress for both cables by 2024, with decision rules needing to be satisfied before progressing through to construction of the first cable. Assuming the project's cost recovery

[49] To be clear, the counterfactual does not include any actionable or future ISP projects. It includes only already committed projects, and small intra-regional augmentations and replacements.

considerations are resolved, timing of first cable would be no later than 2031-32 if TRET is legislated, and 2028-29 if the Step Change scenario were to eventuate.

- QNI Medium and QNI Large are developed by 2032-22 and 2035-36 respectively.
- VNI West is not completed until 2035-36.

However, these quantitative approaches are intended to reveal insights that inform AEMO's decision, rather than bind it to that outcome. To further test the robustness and resilience of candidate DP6 compared to other candidates, AEMO used two additional sensitivity analyses in line with the draft CBA Guidelines: the impact if TRET is legislated, and the materiality of the latest AEMO demand forecasts. This analysis narrowed DP6's quantitative advantage.

D3.1 Approach A: Maximising scenario-weighted net market benefits

The process for the first approach is set out in Box 6 below, with the results presented in Table 8. Candidate DP6 ranks highest in this approach, as it maximises the scenario-weighted net market benefits and delivers positive net market benefits in the Central scenario. See Appendix 2 for rationale behind choice of scenario weightings applied.

Box 6: The mandatory 'scenario-weighted' process

1. Ascribe probabilities to each of the five scenarios (P1,.....P5) and four market event sensitivities (P6,.....P9), acknowledging that ascribing likelihood is inevitably subjective
2. Calculate the total system costs of the first candidate development path, in each of the scenarios: C_1, ..., C_9.
3. Calculate the average scenario-weighted cost A1 of that candidate path across all nine scenarios:
   $A_1 = (C_1*P_1 + C_2*P_2 + ... + C_8*P_8 + C_9*P_9) / 9$
4. Repeat steps 2 and 3 for all eight candidate development paths to reveal (A_1, ..., A_8)
5. The development path with the maximum scenario-weighted benefit from (A_1, ..., A_8) is Candidate DP6.

Table 8 Scenario-weighted net market benefit of each candidate development path (NPV, $ million)

		Scenarios					Market event sensitivities				Weighted net market benefits	Rank
		Central	Step Change	Slow Change	Fast Change	High DER	Early coal closure	Central-West Orana REZ†	Snowy 2.0 delayed	Industrial load closures		
Probability $P_1 \ldots P_9$		20%	10%	5%	15%	10%	10%	15%	5%	10%	A1 … A8	
Development path costs $C_1 \ldots C_9$												
1	Central least-cost	7,688	39,761	-427	14,315	3,900	7,798	8,730	7,679	7,194	11,222	3
2	Slow Change least-cost	7,413	38,333	56	14,172	3,201	7,540	8,465	7,404	6,983	10,857	8
3	Fast Change least-cost	7,564	40,330	-630	14,379	3,965	7,672	8,609	7,556	7,017	11,206	4
4	Step Change least-cost	7,152	40,738	-1,193	14,081	3,620	7,266	8,189	7,144	6,546	10,886	7
5	High DER least-cost	7,479	40,190	-640	14,277	4,004	7,578	8,528	7,471	6,854	11,121	5
6	DP1+ early works ML	7,667	40,738	-419	14,379	3,947	7,778	8,710	7,659	7,173	11,322	1
7	DP1+early works ML and VNI	7,615	40,686	-456	14,326	3,863	7,726	8,658	7,607	7,121	11,268	2
8	DP1+early works ML, accelerated VNI	7,298	40,559	-680	14,051	3,665	7,580	8,307	7,282	6,900	11,014	6

† The net market benefits in this market event sensitivity look greater than the other scenarios and sensitivities as they do not include the cost of the 2 GW of VRE treated as committed in the Central-West Orana REZ. In general, the net market benefits should not be compared across scenarios as they are based on different assumptions, not all of which directly related to the energy sector.

Insights from Approach A

The results reveal that Candidate DP6 (early works on Marinus Link but not on VNI West) maximises the weighted net market benefits under this approach, provided that cost recovery issues are resolved and all the assumptions of that development path hold firm. As discussed in Section D2.2 below, there is a material risk that the assumed new generation capacity will not be in place before the scheduled retirement of Yallourn, leading to increases in consumer bills and a loss of resilience in the system.

All candidate development paths deliver scenario-weighted net market benefits of $11 billion (NPV), reinforcing that strategic investments in transmission infrastructure and REZs, when coupled with low-cost firming resources, will be the most cost-effective way to add capacity and balance variable resources across the whole NEM.

Some notable similarities and differences between the candidate development paths are:

- Under the four market event sensitivities, the least-cost development path for the Central scenario continues to be the least-cost path if the future were known with certainty. In most, the next best scenario optimal path is the Fast Change development path (DP3), with Marinus Link first cable built by 2031-32 resulting in a slight reduction in net market benefits ($120-$126 million NPV). With industrial load closures in both Victoria and Tasmania, the benefit of Marinus Link first cable reduces, with consumers being $176 million NPV worse off under DP3 than DP1. If there are industrial load closures in both regions, the value of supplying the mainland with additional VRE from Tasmania is reduced unless there is also greater interconnection from Victoria to the other NEM regions.
- Early works on Marinus Link provides option value of approximately $100 million (DP6 less DP1) to accelerate the project to 2031-32, or even earlier under the Step Change scenario.
- Accelerating VNI West to 2027-28 (DP8) reduces scenario-weighted net market benefits by $309 million compared to DP6 ($369 million NPV in Central scenario).
- Compared to the Central scenario, early Central-West Orana REZ VRE development reduces the benefits of accelerated VNI West by $34 million NPV (as VNI West now provides fewer capital deferral benefits). A delay in Snowy 2.0 development reduces the benefits of accelerated VNI West by a marginal $8 million NPV.
- Under all but Step Change and High DER scenarios and early Yallourn closure sensitivity, accelerated VNI West also delivers fewer market benefits than the Slow Change scenario least-cost development path, which only includes low-regret transmission solutions.
- However, in all other scenarios and sensitivities, the value of accelerated VNI West increases relative to the Central scenario. In Step Change, the value of early VNI West increases by $190 million. Industrial load closures increase the benefits by $96 million and early coal closure increases the benefits by $171 million.

Appendix 2 provides further detail of the cost benefit analysis and Appendix 4 provides more insights around differences in the energy mix under the various scenarios, sensitivities and candidate development paths.

D3.2 Approach B: Minimising regret costs across all scenarios

Approach A has the merit of offering a clear, single figure of comparison between candidates, and is in any case mandatory under the draft CBA Guidelines.

AEMO has the option to pursue an alternative approach and does so for two main reasons. First, the single probability-weighted outcome tends to obscure significant risks that may be apparent in one or more scenarios, particularly if those scenarios are deemed to have low probability. Second, ascribing the likelihood of probabilities is itself a subjective exercise, over which there may be significant disagreement between market participants.

AEMO has applied an alternate approach to account for the near certainty of change in the economic, trade, security, policy and technology environments in which it operates. Though energy investments must be made, consumers will face increased 'regret costs' if essential investments are delayed or aborted, or are built too early, or generation retirements are brought forward, or large loads close.

AEMO's focus in this step has been on identifying the value of flexibility in the development path. It compares the option value of progressing with Marinus Link or VNI West early works now to allow flexibility (DP6, and DP7) or bringing forward the VNI West investment (DP8), against the two high-performing paths under Approach A that do not have that flexibility (DP1 and DP3). The methodology and results of this approach are set out in Box 7 and Table 9.

Box 7: The alternative 'least-regret' approach

The process for determining least-regret is repeated for all scenarios and market event sensitivites, and the subset of five candidate development paths:

1. For the first candidate development path (D_i), identify the total system costs under the first scenario or sensitivity ($C_{i,j}$).
2. For the same scenario or sensitivity, identify the total system costs from the development path that provides the greatest market benefit in that scenario, assuming perfect foresight (the least cost) (C_{LC}).
3. The 'regret cost' of D_i is the increase in costs ($R_{i,j}=C_{i,j}-C_{LC}$).
4. Repeat steps 2 and 3 across all scenarios and sensitivities to get a range of regret costs ($R_{i,1}....R_{i,9}$), revealing W_i as the worst of the possible regret costs for the development path D_i.
5. Repeat this process for the entire subset of candidate development paths, identifying the range of worst-regret costs ($W_1......W_5$).

Table 9 Regret costs of the subset of candidate development paths (NPV, $ million)

		Scenarios					Market event sensitivities				Maximum regret (W_1 … W_5)	Rank
		Central	Step Change	Slow Change	Fast Change	High DER	Early coal closure	Central-West Orana REZ	Snowy 2.0 delayed	Industrial load closures		
1	Central least-cost	0	-977	-483	-64	-104	0	0	0	0	-977	5
3	Fast Change least-cost	-123	-408	-687	0	-39	-126	-122	-123	-176	-687	3
6	DP1+ early works ML	-20	0	-475	0	-57	-20	-20	-20	-20	-475	1
7	DP1+early works ML and VNI	-72	-52	-512	-52	-142	-72	-72	-72	-72	-512	2
8	DP1+early works ML, accelerated VNI	-389	-179	-736	-328	-339	-218	-423	-398	-294	-736	4

Insights from Approach B

Candidate DP6 (early works on Marinus Link but not on VNI West) continues to be the highest ranked development path under Approach B.

- Early works on Marinus Link is a least-regret decision under this approach, but only if cost recovery issues are resolved. In adopting DP6, the greatest regret costs are experienced if we were to find ourselves in the Slow Change scenario. However, in that case there is little benefit in abandoning Marinus Link if early works have already been completed, as the cost of abandoning it (DP6, $475 M) and delaying it for commissioning in 2036-37 (DP1, $483 M) are almost the same. On the other hand, early works is far more valuable to avoid under-investment should the Step Change scenario occur. The regret cost would then range from $408 M (DP3, if Marinus Link was planned for 2031-32) to $977 M (DP1, if Marinus Link not planned until 2036-37).
- For an accelerated VNI West, the regret costs of both DP7 and DP8 were higher than DP6 in all scenarios, even if Yallourn Power Station closes earlier than expected. In the Central scenario the regret cost of an accelerated VNI West would be $369 million (DP8 – DP6). Even if a Slow change scenario eventuates, it would be better to defer work on VNI West and commit to going ahead with it in 2035-36 no matter what (DP1, $483 million) than spend money on early works now (DP7, $512 million).

However, this is only true with all the assumptions of DP6 holding firm, and in particular, the assumed and projected new replacement dispatchable generation being in place ahead of an early exit of a power station, no material change to the demand forecasts assumed in the Central scenario and cost recovery issues being resolved in respect of Marinus Link. As discussed in section D2.2 below, there is an asymmetric and material risk that the assumed new dispatchable generation capacity will not be in place before the retirement of Yallourn, particularly if Yallourn were to retire earlier than scheduled.

D3.3 Additional sensitivity analyses

To further test the robustness and resilience of candidate DP6 compared to other candidates, AEMO has used additional sensitivity analysis in line with the draft CBA Guidelines. This sensitivity analysis considered:

- the impact if TRET is legislated, and
- the materiality of the latest AEMO demand forecast which includes the COVID-19 impact and updated DER forecasts.

The sensitivity analysis confirmed candidate DP6 as the leading candidate, even if TRET becomes legislated and therefore included in the Central scenario, or if the Central scenario was updated with the latest demand forecasts: see Table 10. However, both sensitivities recognised increased value in an earlier build for Marinus Link and VNI West.

TRET sensitivity

If the TRET is legislated, the potential additional cost of delivering VNI West early reduces from $369 million NPV (in original Central scenario) to $196 million.

Under the TRET, Tasmania's VRE would be about 150% of its needs by 2030, unless there were significant new local energy-intensive industry developed. The surplus would have to be either exported or constrained off. Marinus Link would be needed for the export (assuming cost recovery is resolved), so that candidate development paths with Marinus Link built early rank more favourably than before (such as DP3 and DP5). However, Victoria's own RET will also reach its objective by the 2030s, so Victoria would not need all of Tasmania's surplus, even when Yallourn retires. VNI West would deliver that surplus to New South Wales to help with replacement energy as black coal-fired power stations in that region retire.

Updated demand sensitivity

A revised demand forecast prepared for the 2020 ESOO was used to test the sensitivity of outcomes to changes in demand based on current most-likely expectations. Under this revised forecast, the potential additional cost (reduction in benefit) of delivering VNI West early reduced from $369 million NPV to $189 million (DP6 less DP8): see Table 10. Using these demand forecasts, if Yallourn were to retire early, the reduction in net market benefit of delivering VNI West early rather than late would be only $5 million: see Table 11.

The updated demand forecast prepared for this sensitivity included the estimated impact of COVID-19 and the latest trends in distributed PV sales. While COVID-19 will have a noticeable impact in the next three to five years, the revised growth in DER has a more lasting impact, leading to much lower minimum demands and operational consumption in Victoria. This variability in operational demand, coupled with the increase in VRE to meet VRET, would increase the need for flexibility (storage and/or interconnection) to help balance demand and supply. This increases the value of early VNI West delivery (DP8), and also favours candidates with earlier Marinus Link development (DP3 and DP5).

Table 10 Sensitivity analysis on Central scenario, without early Yallourn closure

Scenario	Net market benefits ($M)			Scenario-weighted ranking*		
Development path	Central	Central with TRET	Central with updated demand	Central	Central with TRET	Central with updated demand
1. Central least-cost	7,688	7,449	7,078	3	4	4
2. Slow least-cost	7,413	6,654	6,802	8	8	8
3. Fast least-cost	7,564	7,644	7,069	4	3	3
4. Step change least-cost	7,152	7,370	6,811	7	7	7
5. High DER least-cost	7,479	7,620	6,941	5	5	5
6. Central, early works ML	7,667	7,677	7,058	1	1	1
7. Central, early works ML + VNI	7,615	7,625	7,006	2	2	2
8. Central, early works on ML + accelerated VNI	7,298	7,481	6,869	6	6	6

* Note – only the Central scenario has been updated with new assumptions. All other scenario results that influence the ranking remain unchanged.

Table 11 Sensitivity analysis on Central scenario, with early Yallourn closure

Scenario	Net market benefits ($M)		Benefits relative to DP6 ($M)	
Development path	Yallourn closure	Yallourn closure with updated demand	Yallourn closure	Yallourn closure with updated demand
1. Central least-cost	7,798	7,112	$20	$20
6. Central, early works ML	7,778	7,092	-	-
7. Central, early works ML + VNI	7,726	7,040	-$52	-$52
8. Central, early works on ML + accelerated VNI	7,580	7,087	-$198	-$5

Part E
ISP projects in the optimal development path

Parts C and D set out the non-grid and network investments that the NEM will need over the next 20 years to deliver low-cost, reliable and secure energy to consumers across a number of scenarios. They confirm that generation in the NEM will evolve from centralised coal-fired generation to a diverse portfolio dominated by DER and VRE, supported by dispatchable resources and enhanced power system service capabilities, and available across a true, interconnected energy highway. Part D also evaluates the candidate development paths to secure that transition.

This Part E identifies the optimal development path for these investments. As discussed in Part A, the optimal development path must not only meet power system and public policy needs and achieve positive net market benefits under the Central scenario, it must also minimise regrets across scenarios and sensitivities. Although this part focuses on the ISP network projects in the optimal development path, AEMO stresses that the path integrates both those projects and the ISP development opportunities of Part C: changing one set is likely to render both the other set, and the whole, sub-optimal.

The sections of Part E are:

1. Accelerating VNI West and Marinus Link in the optimal development path, and
2. The committed ISP projects, and actionable and future ISP projects in the optimal development path.
3. For several of these projects, the ISP also sets out signposts at which an investment decision should be made, and the decision rules which govern those decisions.

Together, these actions and initiatives form a robust, transparent, dynamic roadmap of least-regret choices, to be acted on at significant decision points during Australia's energy transition.

E1 Accelerating VNI West and Marinus Link

As shown in Part D, cost-benefit analysis alone suggests that, if all assumptions are met, candidate DP6 would maximise net market benefits and minimise regret. However, one critical assumption is that the market will introduce sufficient new dispatchable capacity before the next major coal-fired power station in Victoria retires. While market reforms and investment are pushing towards that outcome, it cannot be guaranteed.

This section reveals that:

- If new capacity is not delivered before the coal-generator retirement, as assumed in candidate DP6, the resulting future costs would exceed consumer attitude to risk.
- The most prudent option to mitigate these risks is to bring forward VNI West, provided its costs can be minimised.
- Early completion of Marinus Link will also help mitigate these risks, and is essential to facilitate TRET (if legislated), although it will not progress beyond Final Investment Decision until cost recovery allocation for the project is resolved.

- The most prudent way to create option value is to bring these projects forward by making them actionable, with early works commencing in both cases, and VNI West continuing to delivery, unless circumstances change (as set out in decision rules below), and Marinus Link progressing beyond early works if the TRET is legislated and cost-recovery issues are resolved[50].

AEMO therefore brings forward the timing of both VNI West and Marinus Link in the optimal development path.

E1.1 Material risks with candidate DP6

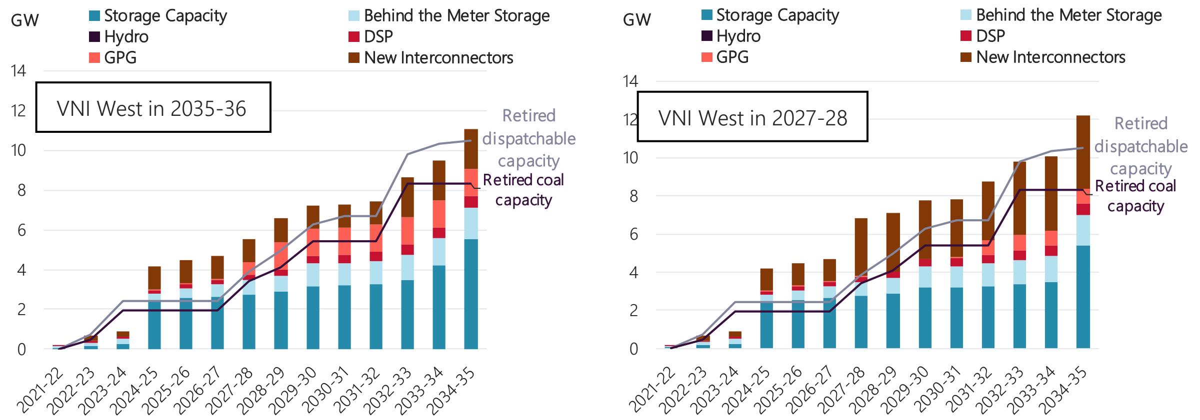
A cost-benefit analysis consistent with the draft CBA guidelines suggests DP6 is the strongest candidate to be the optimal development path. However, this assumes new dispatchable generation is in place before the next retirement of a Victorian coal-fired generation plant. Further, it assumes that forecasts of demand, supply, cost and technology uptake all hold simultaneously. That is extremely difficult to achieve in an inherently uncertain world. While scenarios can capture these uncertainties to some degree, the timings and probabilities of market events that pose system risks are intrinsically difficult to assess.

There are several reasons to be concerned about these assumptions, which potentially mask significant risks to consumers:

- **Uncertain delivery of utility-scale storage.** The Central scenario and its two related sensitivities (TRET and updated demands) project that utility-scale storage (up to 1.3 GW of 2-4 hours duration) will be the most cost-effective way to meet demand in Victoria and balance energy resources if Yallourn closes earlier than scheduled. These storages will also be required before any coal-fired generation retires, to manage reliability and to help increase minimum demand. That delivery depends on their technology costs declining as assumed, market and regulatory incentives being in place, and investor confidence standing firm in the face of Marinus Link and VNI West being built in the 2030s. To date, there is no evidence of anticipated projects being progressed to meet these needs in Victoria in the next decade. If no utility-scale storage is developed in the next decade across the NEM, beyond what is currently committed (primarily Snowy 2.0), and Yallourn closes early, up to 1.3 GW of GPG would be required instead to maintain reliability in all regions (see Figure 22 below). While this new GPG will help meet peak demand, particularly after coal-fired generation retires, it will do little to shift VRE and DER to help balance inter- and intra-day demand and supply: see Section C3.2 above. This would reduce the market benefits of DP6 under the updated demand Central sensitivity with early Yallourn closure by $294 million.

[50] See AER draft Cost benefit analysis guidelines pages 35-40.

Figure 22 Announced retirements and corresponding dispatchable capacity builds in Central scenario with updated demand and early coal closure – no new market-based dispatchable storage until 2032

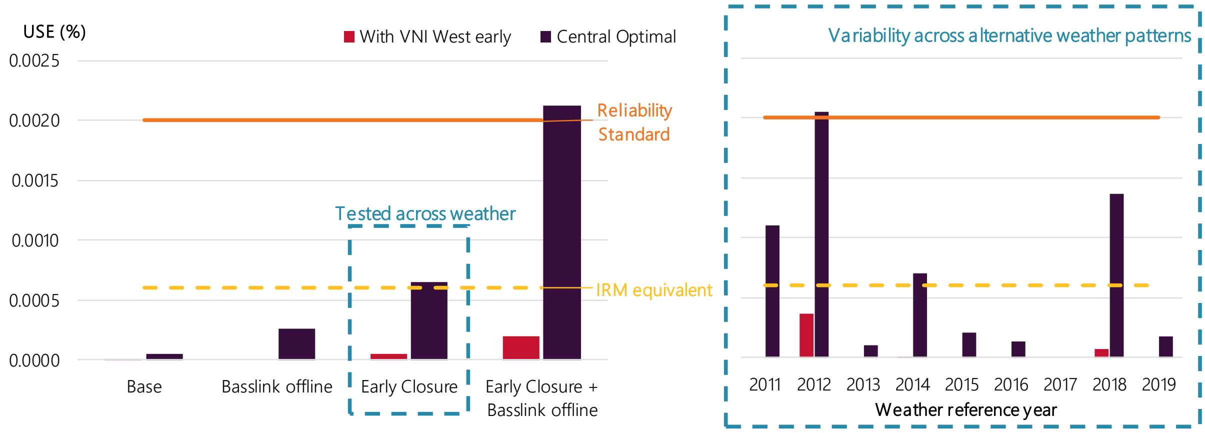


- **Reduction in coal-fired generation due to ramping.** Victorian brown coal power stations will be required to ramp up and down in response to relatively rapid variations in both demand and supply during the day, as VRE and DER expands in Victoria. The need for ramping will increase if more distributed PV is installed (as in the updated demand sensitivity) Detailed half-hourly analysis shows that, under DP6, generators are assumed to ramp far more frequently than historically observed and either decommit units or operate at minimum stable levels more often to accommodate solar generation in the middle of the day: see Appendix 6. Alternatively, VRE energy may be spilled, reducing the likelihood that VRET will be met. Continual ramping may also require increased maintenance and planned outages and may potentially increase the risk of unplanned outages. VNI West would allow coal-fired generation to operate more stably while supporting increasing renewable generation, to improve plant reliability and reduce operating and maintenance costs.
- **Uncertainty of demand reduction drivers.** The forecast that growth in maximum operational demand in Victoria will be relatively subdued (at least until EVs are adopted at scale) depends on a number of assumptions that are inherently uncertain. These include the effectiveness of Victoria's energy efficiency schemes, the timing of broader adoption of batteries in homes, the timing of EVs reaching price parity with combustion engines, the extent of growth in DSP, and the success of VPP trials. The High DER and Step Change scenarios consider the greater uptake of many of these technologies. But if these consumer-led changes do not occur as rapidly as assumed, peak demand in Victoria could be as much as 500 MW higher by 2027-28 than currently forecast in the Central scenario. Importantly, the updated ESOO demand forecast is now projecting Victorian demand to be 200-250 MW higher by 2027-28 than previously thought.
- **System security risks.** The variability in demand extremes projected in the updated demand sensitivity (now considered to be the most likely forecast of demand and DER) is also of concern from a system security perspective. At times such as weekends when distributed PV generation is high and demand is relatively low, thermal generation may be forced to shut down unless Victoria has sufficient export capability. Those shutdowns could create serious operational issues, including high voltages, reductions in system strength and, potentially, concerns about regional frequency control. This may in turn require additional network investments or services to manage the anticipated operational challenges. Further

power system analysis is currently being progressed to determine the full implications given that the demand forecasts have only just been produced.

- **Additional resilience against system shocks.** VNI West improves the resilience of the power system to withstand high impact low probability (HILP) events such as prolonged generation or transmission outages or extreme weather events once Yallourn closes: see Figure 23 below. The multiple system shocks of the 2019-20 summer are instructive. The VNI West project would deliver a material uplift in the resilience of the national grid, as well as mitigate co-incident shocks such as a Basslink outage, coal plant failure, peak demand period, protracted wind drought or impaired PV production due to fire and smoke haze. Without VNI West, more Reliability and Emergency Reserve Trader (RERT) may need to be procured (assuming it is available) or more dispatchable capacity may be required to deliver on community expectations that electricity supply will remain reliable during a "1 in 10 year" summer.

Figure 23 Sensitivity to HILP events, with and without VNI West



E1.2 The prudent path to address those risks

As a priority, AEMO will work closely with the ESB and AEMC to ensure the market reforms needed to incentivise the needed dispatchable capacity are effectively progressed. However, AEMO must also consider whether an earlier delivery of VNI West and/or Marinus Link protects consumers against an early coal closure before the market has delivered sufficient utility-scale storage.

For the reasons given above, AEMO has concluded that VNI West should be progressed for delivery by 2027-28, as long as its costs are appropriate and adequate market-based alternatives do not emerge as anticipated projects before construction commences. The project provides the design choices, operational flexibility and resilience needed to mitigate that material risk better than the alternatives. AEMO also notes the asymmetric risk that delivery too late carries far higher cost and risk than delivery slightly early.

Marinus Link, if accelerated, could provide effective risk mitigation to plant outages, early failures or coincident 'non-credible' contingencies such as a simultaneous outage of Basslink and a period of low wind production. However, unless cost recovery and allocation are resolved, there is no certainty that Marinus Link will be able to proceed. Therefore, to be prudent, both projects should be accelerated to preserve their option value. Even with Marinus Link, VNI West would provide value by delivering surplus supplies from Tasmania to New South Wales as coal-fired generation retires in that region.

Cost ceiling on VNI West

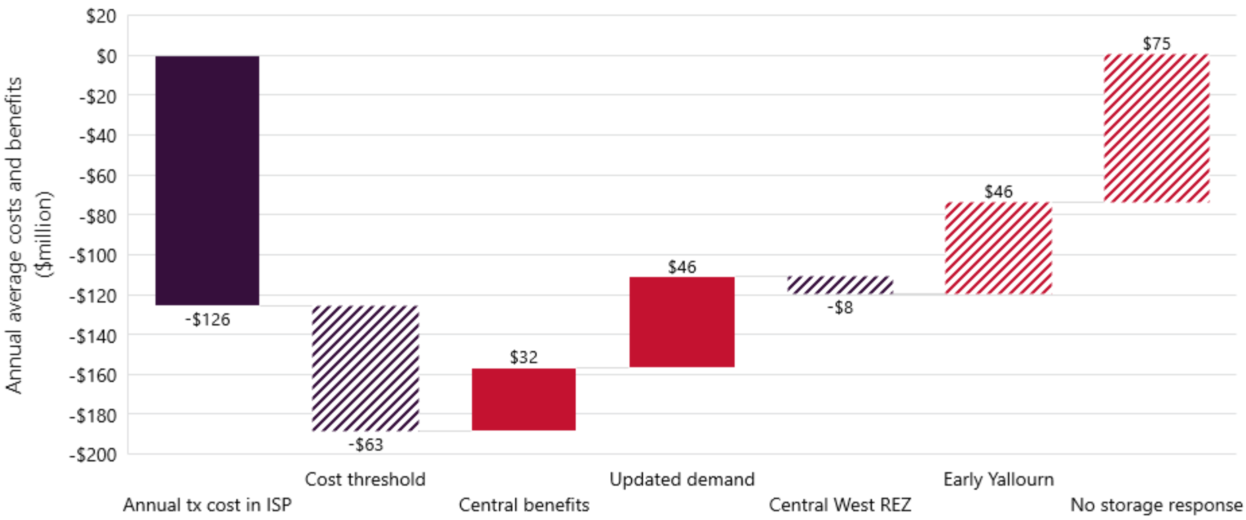
AEMO will work closely with the TNSPs and Governments to ensure the project can be completed at an efficient cost to optimise benefits for consumers. Preliminary analysis indicates that the project would need to be completed for less than $2.6 billion, at which point new local GPG alternatives may be able to meet reliability and system security requirements more cost-effectively, though would do little to address the other identified needs of this project (see table 12). Beyond that ceiling, consumers may bear an inappropriate quantum of cost of the project. The project should be commenced with a focus to maintain costs to consumers under $2.6 billion. This cost estimate is for guidance only and does not negate the need for the project to demonstrate it delivers positive net market benefits.

Figure 24 below draws from the preliminary analysis to summarise how the VNI West delivers positive net market benefits to consumers when the cost is below $2.6 billion, using annualised equivalent costs and benefits for ease of comparison. Looking at the columns from left to right:

- At $2.6 billion, the equivalent annuity assuming a 50 year life and 5.9% weighted average cost of capital is around $189 million, once operational expenditure is taken into account. This ISP currently assumes a cost for VNI West of $1.73 billion ($126 million annual equivalent).
- The average annual gross benefits of developing VNI West by 2027-28 rather than 2035-36 under the Central scenario are approximately $32 million. However, these benefits increase significantly if the risks and advantages discussed above are taken into account.
- Using updated demand forecasts increases the annual average benefits of accelerated VNI West development by $46 million.
- If Yallourn were to retire in full by 2027-28, the annual average benefits of accelerated VNI West development increase a further $46 million.
- If there was no market-based energy storage available before 2032, and 1.3 GW of new GPG needed to be developed instead, the capital deferral benefits and fuel cost savings of accelerated VNI West development increase a further $75 million.
- Reductions in voluntary or involuntary load shedding of, on average, 800 MWh per year would increase the value of accelerated VNI West by $36 million, assuming the current Value of Customer Reliability (VCR) of $45,000/MWh[51]. This serves as a proxy for some of the reliability risks are associated with forecast uncertainty, discussed below.

[51] VCR is used in planning to represent a customer's willingness to pay for the reliable supply of electricity. For more see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/value-of-customer-reliability.

Figure 24 Indication of cost ceiling



Clearly, the lower the VNI West cost can go below this threshold, the greater the value delivered to consumers.

Qualitative advantages of VNI West over the alternatives

The above cost threshold does not include any premium for VNI West's additional benefits and externalities that are not incorporated in the CBA, but are valuable to third parties or governments.

The additional advantages and externalities of accelerating VNI West are:

- **Better protection against scarcity risk and its impact on consumer bills**. Over the past decade, increased scarcity of supply followed closure of coal generators in South Australia and Victoria, allowing remaining coal generators to increase their offer price towards that offered by GPG, even when GPG was not operating (effectively shadow pricing GPG). Competition theory suggests that generator bids would shift towards a more cost-reflective position as scarcity is reduced and competition increases. Regional interconnectors reduce customers' exposure to scarcity pricing, by creating competitive tension between a greater number of generators. VNI West maximises the number of supply sources, by accessing New South Wales generators and Snowy 2.0, and not just Victorian sources (regional storage and GPG) or Tasmanian sources (Marinus Link). If this increased competition encourages generators to bid more cost-reflectively, in line with competition theory, VNI West will put downward pressure on prices for Victorian consumers.
- **Support for Victorian RET and VRE, including additional choices for VRE capacity.** While new GPG could help maintain reliability in Victoria, meeting VRET would become highly challenging; without storage or new interconnection, VRE would need to be spilled or DER constrained at times of high renewable penetration. While a future hydrogen industry may be able to help by effectively storing excess VRE in that form, its development is uncertain and still some time off: see Appendix 10. Interconnection in the form of VNI West helps secure the VRE and DER contribution to the VRET. An accelerated VNI West also supports VRE investment and the VRET in three other related ways.
  - First, it would maximise the location choices for additional VRE capacity. The ISP modelling seeks to minimise the *combined* cost of generation and transmission investment. Under DP6, the lowest cost outcome is to develop VRE in REZs with existing spare hosting capacity, but not necessarily

the highest quality resources. This is not well aligned with developer interest, which is instead focused in areas where resource quality is greatest, such as south-west and western Victoria (primarily for wind) and Murray River and Central North Victoria (primarily for solar). VNI West would help connect more VRE in areas where developer interest is strongest.

  - Second, it would provide investor certainty with respect to where and when new transmission will be located, and therefore where best to invest.
  - Third, it would assist in securing vital community and planning support for VRE projects, so they can be delivered when required, and not unduly delayed. In relevant areas, VNI West will help align the interests of energy consumers, developers and local communities, and so maintain development efficiency and the likelihood that VRET will be met.

- **Support for Snowy 2.0.** Finally, VNI West would increase Victoria's access to Snowy's deep storage, if required, to cover prolonged outages of generation or transmission (for example, Basslink), particularly following the closure of Yallourn.

AEMO therefore concludes it is prudent to include the accelerated development of VNI West in the optimal development path: to ensure no shortfall in generator capacity exists when Yallourn exits, to safeguard Victorian consumers form co-incident systemic shocks, and to enable Victorian consumers to enjoy the full benefit of access to the resources of the Snowy 2.0 project from its completion date.

E1.3 Accelerating projects, with decision rules

The delivery dates for both VNI West and Marinus Link should be brought forward in the optimal development path, with early works commenced as soon as practicable. The most prudent way to do this within the NER is for each to be an actionable ISP project with a single RIT-T process.

Decision rules for VNI West

Due to long lead times, it is prudent to commence VNI West immediately to mitigate risk of delivering too late if other market investments have not been developed as hoped.

VNI West is therefore specified as a single RIT-T process as follows:

- Complete early works by late 2024, and
- Complete the project by no later than 2027-28, unless decision rules require pausing or cancellation.

The decision rules that would result in VNI West being paused or cancelled include:

- transmission costs, including any third-party contribution, exceeding $2.6 billion, or
- sufficient new market-based dispatchable capacity being in place in Victoria ahead of the next brown coal closure in Victoria, or
- the Slow Change scenario unfolding, which includes life extensions of existing coal-fired generation.

As discussed in Section C2.3, should the decision rules not be met, then the deferral or change of this project will also impact the REZ associated with it.

Decision rules for Marinus Link

Marinus Link is a multi-staged actionable ISP project to be completed from 2028-29, with early works recommended to start as soon as possible, and with further stages to proceed if their respective decision rules are satisfied.

The cost-benefit analysis recognised the option value of early works on Marinus Link. TasNetworks advises that the earliest the first cable can be operational is 2028-29, leveraging work to date on the current RIT-T. That is when it would be required under the Step Change scenario. If other scenarios or sensitivities unfold such that the cable is needed by 2031-32, that represents only a three-year contingency to allow for potential delays in the planning approvals or construction works. As well, additional time and effort would be required to undertake separate RIT-Ts for early works and cable construction of the first cable.

For these reasons, it is prudent to maintain momentum on the current Marinus Link RIT-T and continue progressing early works for both cables through to Final Investment Decision in 2024. If, by then, the Tasmanian Government has legislated the TRET, and if there has been successful resolution on how the costs will be recovered from consumers, Stage 1 of the project (the first cable) can still be completed in time to optimise benefits to consumers.

Marinus Link is therefore specified as a multi-staged actionable ISP project with a single RIT-T process as follows:

- Complete early works on both cables by no later than 2023-24
- Stage 1 of the project, as described by TasNetworks in its PADR, is to construct the first cable from 2028-29 should the Step Change scenario eventuate, and by no later than 2031-32, if decision rules are satisfied. The decision rules for Marinus Link to proceed from early works to construct the first cable include:
  - there is successful resolution as to how the costs of the project will be recovered (from consumers or other sources), and
  - either TRET is legislated, or, either the Step Change or Fast Change scenario unfolds.
- Stage 2 of the project, as described by TasNetworks in its PADR, is to construct the second cable if further decision rules are satisfied. The decision rules for Marinus Link to proceed to construct the second cable will be specified in the 2022 ISP, with the intent that this stage continues to be assessed to deliver value at that time.

Guidance for RIT-T proponents

In terms of adopting other elements of the optimal development path in their RIT-T, AEMO recommends that the RIT-T proponent apply decision rules based on circumstances at the time the RIT-T commences. This means, ISP projects that proceed unless circumstances change (such as VNI West) should be included at the accelerated delivery date, whereas ISP projects that proceed if circumstances change (such as Marinus Link) should not, and instead, only be tested as a sensitivity.

E2 Network investments in the optimal development path

The optimal development path defines the project and timing of 18 network investments to fulfil NEM cost, security and reliability expectations through a complex energy sector transition. To contribute their full value, these projects should be complemented by staging, preparatory activities, ISP development opportunities, and policy reforms.

The architectural design of network augmentations has been developed to also support identified REZ development opportunities. The REZs and their related transmission needs were designed as part of an integrated system within the wider shared network, and considering also future needs (for example, designing the augmentations either as stages of, or at least to be compatible with, future ISP projects, to reduce the overall costs for implementation and the need for additional investments).

Details of the network investments in the optimal development path are set out in Table 14 and visually in Figure 25 (the optimal development path in the NEM).

In summary, those projects are:

- **Committed ISP projects**, already underway.
  - **South Australia system strength remediation,** on track to be completed in 2021
  - **Western Victoria Transmission Network Project,** on track to be completed in two stages, by 2021 and 2025, and
  - **QNI Minor,** on track to be completed in 2021-22.
- **Actionable ISP projects**, either already progressing or to commence immediately after the publication of the 2020 ISP. These are estimated practical completion timings of the projects including any subsequent testing; the projects will be optimal and deliver benefits to consumers if they can be delivered earlier than these timings.
  - **VNI Minor**, expected to be completed in 2022-23.
  - **Project EnergyConnect**, expected to be completed by 2024-25. The implementation of this project is currently tracking ahead of schedule with commissioning targeted in stages between late 2022 and late 2023 followed by 12 months of testing.
  - **HumeLink**, expected to be completed by 2025-26.
  - **Central-West Orana REZ Transmission Link**[52]**,** expected to be completed in 2024-25.
- **Actionable ISP projects with decision rules,** with early works to start as soon as possible. The decision rules identified in this ISP for these actionable ISP projects can be assessed during the RIT-T process and will be confirmed by AEMO as part of the ISP feedback loop process with the TNSP once the decision rule eventuates[53].
  - **VNI West**, to be progressed as a project for delivery by 2027-28.
  - **Marinus Link**, to be progressed as a staged project for delivery from 2028-29.
- **Future ISP projects,** for which AEMO requires the responsible TNSP to carry out preparatory activities including publishing a report on the outcome of these activities by 30 June 2021. These projects would reduce costs, and enhance system resilience and optionality. They are not yet 'actionable' under the new ISP Rules, but are expected to be so in the future and are part of the optimal development path. Further details on these future projects are provided in Table 13. A complete list of all future ISP projects is provided in Table 14.
  - **QNI Medium and Large interconnector upgrades,** between 2032-33 to 2035-36[54].
  - **Central to Southern Queensland Transmission Link,** in the mid-2030s.
  - **Gladstone Grid Reinforcement,** between 2024-25 to 2034-35.

[52] New South Wales Government. *New England to light up with second NSW Renewable Energy Zone*, at https://www.nsw.gov.au/media-releases/new-england-to-light-up-second-nsw-renewable-energy-zone

[53] Clause 5.16A.5 NER

[54] Some parts of these upgrades may be needed earlier if the New England REZ development is accelerated through New South Wales Government policy.

- Reinforcing Sydney, Newcastle and Wollongong Supply reinforcement**, between 2026-27 and 2032-33.
  - **New England REZ network expansion**, between 2031 to 2036[55].
  - **North West New South Wales REZ network expansion**, in the 2030s depending on connection interest.
- **Additional future ISP projects, for which no action is required before the next ISP.** These projects would also reduce costs, and enhance system resilience and optionality.
  - **Far North Queensland network and REZ expansion,** between 2035-36 and 2037-38 (or possibly as early as 2031 if Step Change scenario eventuates).
  - **Mid North South Australia network project,** between 2034-35 to 2035-36.
  - **South East South Australia network expansion,** in the late 2030s (or possibly as early as 2030-31 if Step Change scenario eventuates).

AEMO has issued a call for submissions[56] on non-network options for the Central-West Orana REZ Transmission Link project. Submissions are requested by 22 October 2020. Following the close of consultation, submissions will be reviewed with TransGrid, and any that meet the identified need will be referred to TransGrid for review as part of its RIT-T on this ISP project.

[55] The New England REZ network expansion may be accelerated through New South Wales Government policy (see https://www.nsw.gov.au/media-releases/new-england-to-light-up-second-nsw-renewable-energy-zone).

[56] Clauses 5.22.12 and 5.22.14 (c)(1) of the NER

Table 12 Details of actionable ISP projects

Project	Responsible TNSP(s)	Identified need	ISP candidate option†	Scenarios of relevance for TNSP under ISP Framework
VNI Minor **PADR completed in 2019**	AEMO Victorian Planning and TransGrid	To realise net market benefits by increasing the power transfer capability from Victoria to New South Wales.	VNI Minor is a minor upgrade of the existing Victoria – New South Wales interconnector with installation of an additional 500/330 kV transformer, uprating to increase thermal capacity of the existing transmission, and installation of power flow controllers to manage the overload of transmission lines.	Not applicable RIT-T complete
Project EnergyConnect **PADR completed in 2018**	ElectraNet and TransGrid	To deliver net market benefits and support energy market transition through: • Lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions. • Facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources across regions. • Enhancing security of electricity supply in South Australia.	Project EnergyConnect is a new HVAC 330 kV double-circuit interconnector between New South Wales and South Australia. The network project is approximately 916 km from Robertstown in South Australia to Wagga Wagga in New South Wales, connecting with the north most section of the Victorian Transmission network.	Not applicable RIT-T complete
HumeLink **PADR completed February 2020**	TransGrid	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.	HumeLink is a proposed transmission network augmentation that reinforces the New South Wales southern shared network to increase transfer capacity to the region's demand centre (i.e. the Greater Sydney area). The proposed 500 kV transmission upgrades span a distance of approximately 630 km between the Snowy Mountains Hydroelectric Scheme and Bannaby.	Central (40%), Slow Change (10%), Step Change (20%), Fast Change (30%)[57]

[57] Scenarios are aligned with selection already being progressed through the regulatory process by TransGrid to avoid any unintended transitional issues.

Project	Responsible TNSP(s)	Identified need	ISP candidate option†	Scenarios of relevance for TNSP under ISP Framework
Central-West Orana REZ Transmission Link **PADR required by December 2021**	TransGrid	To increase the capability of the transmission network to enable the connection of expected generation in the Central-West Orana REZ: • increasing the transfer capacity between expected generation in the Central-West Orana REZ and the existing 500 kV transmission network between Bayswater, Wollar and Mount Piper, and • ensuring sufficient resilience to avoid material reductions in transfer capacity during an outage of a transmission element, or as otherwise consistent with the NSW Government's Central-West Orana REZ program, including any change of law.	Central-West Orana REZ Transmission Link is a single circuit 500 kV HVAC loop which traverses the Central-West region, cutting in to the existing 500 kV line between Bayswater and Wollar, and returning to Wollar, and including a tie into the existing 330 kV network in the Central-West Orana region.	Central, 100%
VNI West **(with decision rules) ‡** **PADR required by March 2021**	AEMO Victorian Planning and TransGrid	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.	VNI West is a proposed new interconnection between Victoria and New South wales, involving a new 500 kV HVAC double circuit line from: • A new substation north of Ballarat to Bendigo to Shepparton to Wagga Wagga or, • A new substation north of Ballarat to Kerang to Darlington Point (or Dinawan) to Wagga Wagga. Both routes also include associated transformers, power flow controllers, and reactive equipment.	Central with updated demand and early Yallourn closure (100%) assuming decision rules are satisfied. This means the modelling should assume there is no new market-based dispatchable storage until 2032-33.
Marinus Link **(with decision rules) ‡** **PADR completed in December 2019**	TasNetworks and AEMO Victorian Planning	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.	Marinus Link is a second, and potentially third, HVDC cable interconnection between Tasmania and Victoria. It is proposed with a transfer capability of 750 MW (one cable) or 1,500 MW (two cables).	Central with TRET (67%), and Step Change (33%)

† Indicative outline of the recommended option for project delivery
‡ These requirements can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate. These projects are also critical to address cost, security and reliability issues.

Table 13 Preparatory activities are required on these future ISP projects

Project	Indicative timing †	Status	Responsible TNSP(s)	Preparatory activities required
QNI Medium & Large	2032-33 to 2035-36	RIT-T not started	Powerlink and TransGrid	AEMO requires that the responsible TNSPs undertake the following preparatory activities by 30 June 2021 for each project listed in this table, including publishing a report on the outcome of these activities: • Preliminary engineering design. • Desktop easement assessment. • Cost estimates based on preliminary engineering design and route selection. • Preliminary assessment of environmental and planning approvals. • Appropriate stakeholder engagement.
Central to Southern Queensland Transmission Link	Mid-2030s	RIT-T not started	Powerlink	
Gladstone Grid Reinforcement	2024-25 to 2034-35	RIT-T not started	Powerlink	
Reinforcing Sydney, Newcastle and Wollongong Supply	Between 2026-27 and 2032-33	RIT-T not started	TransGrid	
New England NSW REZ Network Expansion‡	2030-31 to 2035-36	RIT-T not started	TransGrid	
North West NSW REZ Network Expansion	2030s	RIT-T not started	TransGrid	

† The earliest time by when the full ISP project has been found to needed in the optimal development path. All dates are indicative, and on a financial year basis.
‡ The New England REZ network expansion may be accelerated through New South Wales Government policy: see New South Wales Government. *New England to light up with second NSW Renewable Energy Zone*, at https://www.nsw.gov.au/media-releases/new-england-to-light-up-second-nsw-renewable-energy-zone.

Table 14 Summary of network investments in the optimal development path

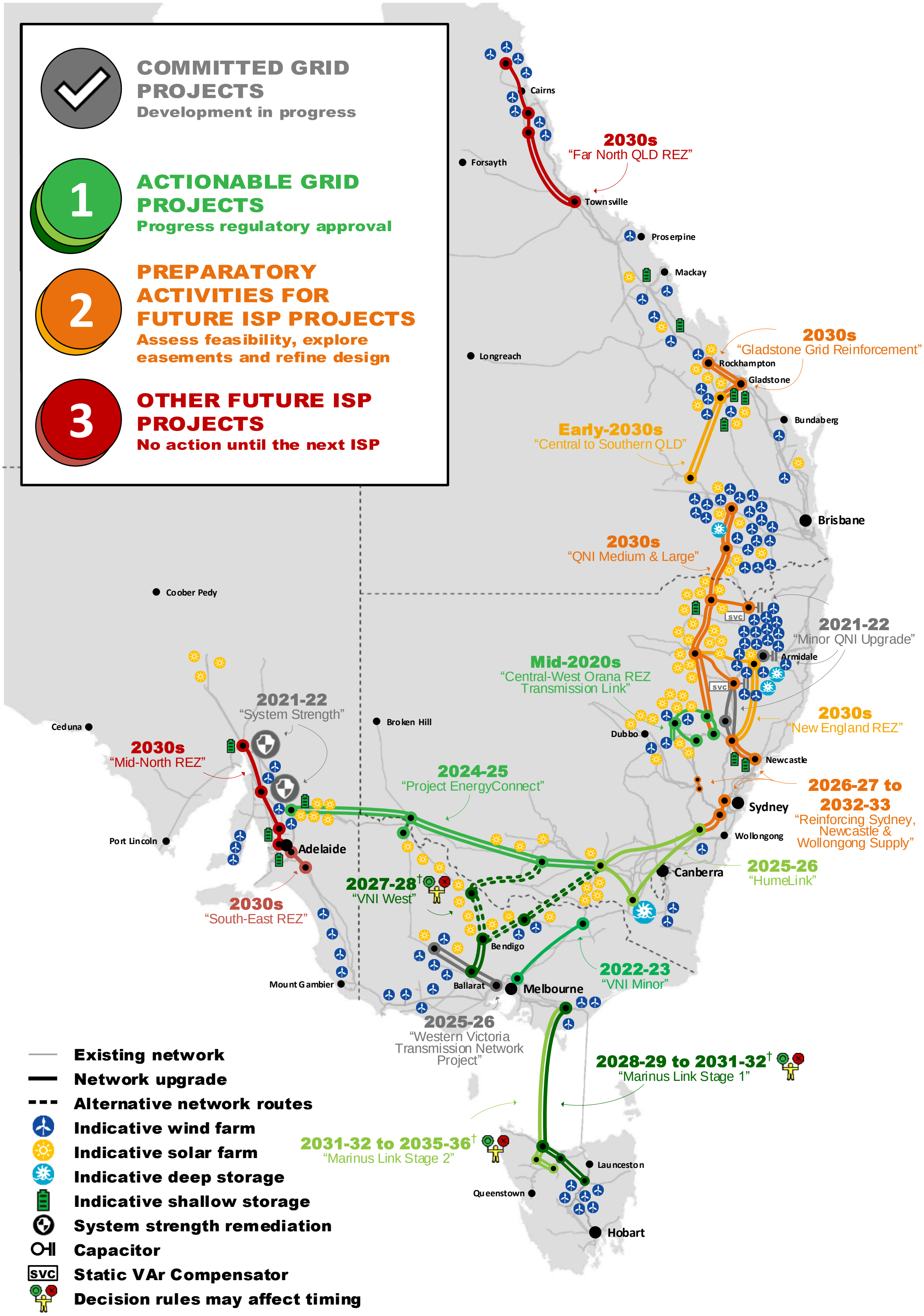
Project	Timing identified in optimal development path	Status	Cost range [modelled cost]	Network capability improvement
Committed ISP projects				
SA system strength remediation	2021-22	Complete	Committed project	Maintain system security
QNI Minor	2021-22	Complete	Committed project	NSW-QLD (North): +150 MW NSW-QLD (South): 165 MW to 215 MW
Western Victoria Transmission Network Project	2025-26	Complete	Committed project	This project will increase the hosting capacity in the Western Victoria REZ to cater for all existing and committed generation (at the time of the RIT-T completion) with approximately 450 MW of remaining hosting capacity.

Project	Timing identified in optimal development path	Status	Cost range [modelled cost]	Network capability improvement
Actionable ISP projects				
VNI Minor	2022-23	RIT-T Complete VIC works: Committed NSW works: Pending TransGrid CPA	$74 million to $137 million [$105 million]	VIC-NSW (North)=: +170 MW
Project EnergyConnect	2024-25 (with staging from late 2022)	RIT-T complete Pending CPA	$1,393 million to $2,587 million [$1,990 million]	SA-NSW +800 MW SA –VIC +100 MW Riverland REZ: +800 MW Murray River REZ: + 600 MW South-west NSW REZ: +380 MW
HumeLink	2025-26	PADR complete Pending PACR (late 2020)	$1,470 million to $2,730 million [$2,100 million]	Snowy to Sydney +2,230 to 2,570 MW Wagga Wagga REZ: +1,000 MW
Central-West Orana REZ Transmission Link	2024-25	RIT-T not yet commenced	$450 million to $850 million [$650 million]	Central-West Orana REZ: +3,000 MW
Actionable ISP projects with decision rules				
VNI West	2027-28 (conditional on decision rules being satisfied)	PSCR Complete Pending PADR (March 2021)	Shepparton Route: $1211 million to $2249 million [$1,730 million] Including early works up to $150 million	VIC-NSW (North): +1,930 MW VIC-NSW (South): +1,800 MW Central North Vic REZ: +2,000 MW Western Victoria REZ: +1,000 MW
			Kerang Route: $1,687 million to $3,133 million [2,410 million] Including early works up to $200 million	VIC-NSW (North): +1,930 MW VIC-NSW (South): +1,800 MW South West NSW REZ: +1,000 MW Murray River REZ: +2,000 MW Western Victoria REZ: +1,000 MW

Project	Timing identified in optimal development path	Status	Cost range [modelled cost]	Network capability improvement
Marinus Link	Project Stage 1 1st cable: between 2028-29 and 2031-32 (conditional on decision rules being satisfied) Project Stage 2 2nd cable: between 2031-32 and 2035-36 (conditional on decision rules being satisfied)	PADR complete Pending PACR	Marinus Link Stage 1 – $1,292 million to $2,399 million [$1,845 million] Marinus Link Stage 2 – $2,209 million to $4,102 million [$3,155 million] Early works up to $140 million (for both cables)	TAS – VIC (both directions): - Stage 1: +750 MW - Stage 2: +1500 MW (combined stage 1 and stage 2) REZ hosting capacity increase: - Stage 1: +540 MW Midlands - Stage 2: +600 MW North West Tasmania, +1,080 MW Midlands (combined stage 1 and stage 2)
Future ISP projects				
QNI Medium & Large	2032-33 to 2035-36	RIT-T not started	QNI Medium: $1,481 million to $2,750 million [$2,115 million] QNI Large: $802 million to1,489 million [$1,145 million]	QNI Medium: +832 MW (NSW to QLD) +760 MW (QLD to NSW) North West NSW: +1,000 MW Darling Downs: +1,000 MW QNI Large: (combined improvement) +2,372 MW (NSW to QLD) +2,130 MW (QLD to NSW) North West NSW: +2,000 MW Darling Downs: +2,000 MW
Central to Southern Queensland network project	Early-2030s	RIT-T not started	$300 million to $560 million [$432 million]	Increase Transfer across CQ-SQ: +900 MW
Gladstone Grid Reinforcement	2025 to 2035	RIT-T not started	$300 million to $560 million [$432 million]	Fitzroy REZ: +800 MW
Reinforcing Sydney, Newcastle and Wollongong Supply	Between 2026-27 and 2032-33	RIT-T not started	Uncertain – Pending Preparatory Activities	Stages 1 & 2: Between 5,000 MW and 6,000 MW
New England NSW REZ network expansion	2031 to 2036 May be accelerated by NSW government to meet announced target for development of the REZ	RIT-T not started	Stage 1: $720 to 1,330 million [$1,025 million] Stage 2: $220 to $420 million [$320 million]	Additional REZ hosting capacity Stage 1: 3,000 MW to 4,000 MW Stage 2: 4,000 MW to 5,000 MW (including stage 1)

Project	Timing identified in optimal development path	Status	Cost range [modelled cost]	Network capability improvement
North West NSW REZ network expansion	2030s, based on connection interest	RIT-T not started	Stage 1: $ 320 million to $590 million [$455 million] Stage 2: $70 million to $140 million [$105 million] Stage 3: $220 million to $420 million [$320 million]	Additional REZ hosting capacity Stage 1: +1,000 MW Stage 2: +3,000 MW (4,000 MW in total)
Far North Queensland network and REZ expansion	2030s, based on connection interest (2031 in the Step Change scenario)	RIT-T not started	Stage 1: $400 million to $740 million [$570 million] Stage 2: $280 million to $530 million [$405 million]	Enable the connection and transfer of energy from Far North Queensland. Additional REZ hosting capacity Stage 1: +500 MW Stage 2: +700 MW
Mid North SA network project	2034-35 to 2035 36	RIT-T not started	$420 million to $770 million [$595 million]	Alleviate constraints between Davenport and Adelaide and between Davenport and Robertstown to support Additional REZ hosting capacity +1,000 MW
South East South Australia network expansion	Late 2030s (2030-31 in the Step Change scenario)	RIT-T not started	$20 million to $80 million [$50 million]	To facilitate the connection of wind generation of 400 MW to 600 MW on the South Australia side of the Heywood interconnector

Figure 25 Optimal development path for the NEM



† The timing of these actionable projects is dependent on decision rules.
All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

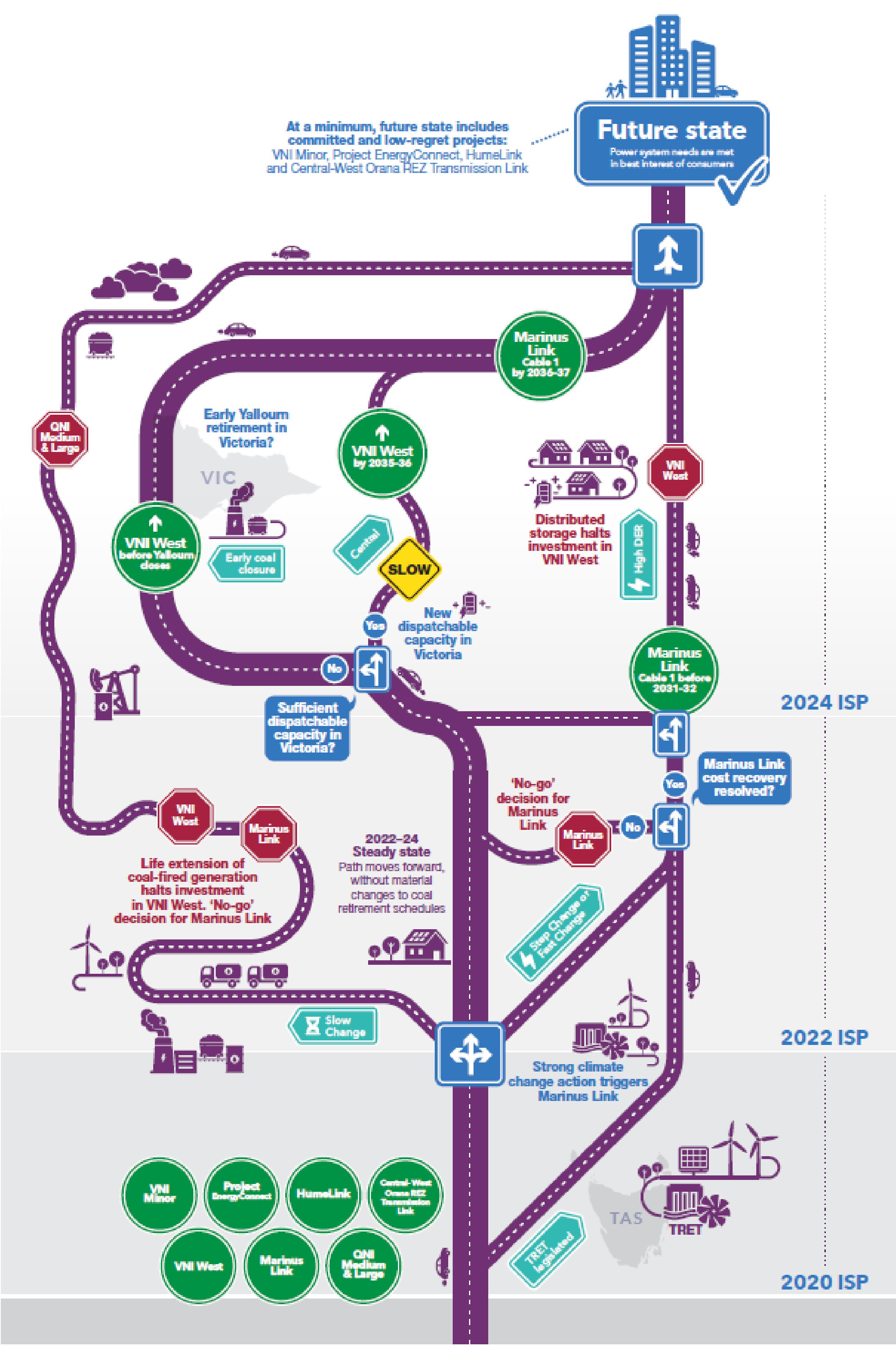
E3 Decision signposts if the environment changes

A dynamic roadmap is essential for the NEM to have both certainty and flexibility, and so meet the cost, security, reliability and emissions expectations of energy consumers through the energy transition. That roadmap is shown in Figure 26, with potential changes being:

- If there is sufficient market-based dispatchable capacity in Victoria to maintain reliability in the event that brown coal-fired generation in Victoria is retired early or becomes increasingly unreliable, then slow down delivery of VNI West. Similarly, if transmission project costs cannot be retained to an efficient level of $2.6 billion, then the timing and scope of the investment should be reassessed.
- If we find ourselves in the Slow Change scenario, then AEMO will reassess the need to progress development of Marinus Link and VNI West.
- If TRET is legislated, or we find ourselves in the Fast Change scenario, and there is successful resolution as to how the costs of Marinus Link project will be recovered, then Marinus Link's first cable should be completed by 2031-32.
- If we find ourselves in the Step Change scenario and there is successful resolution as to how the costs of Marinus Link project will be recovered, then accelerate completion of both Marinus Link cables as much as possible.

If the 2022 ISP confirms the value of Marinus Link's second cable, then decision rules for this stage will be established at that time.

Figure 26 Dynamic roadmap with choices to be acted on at significant decision points



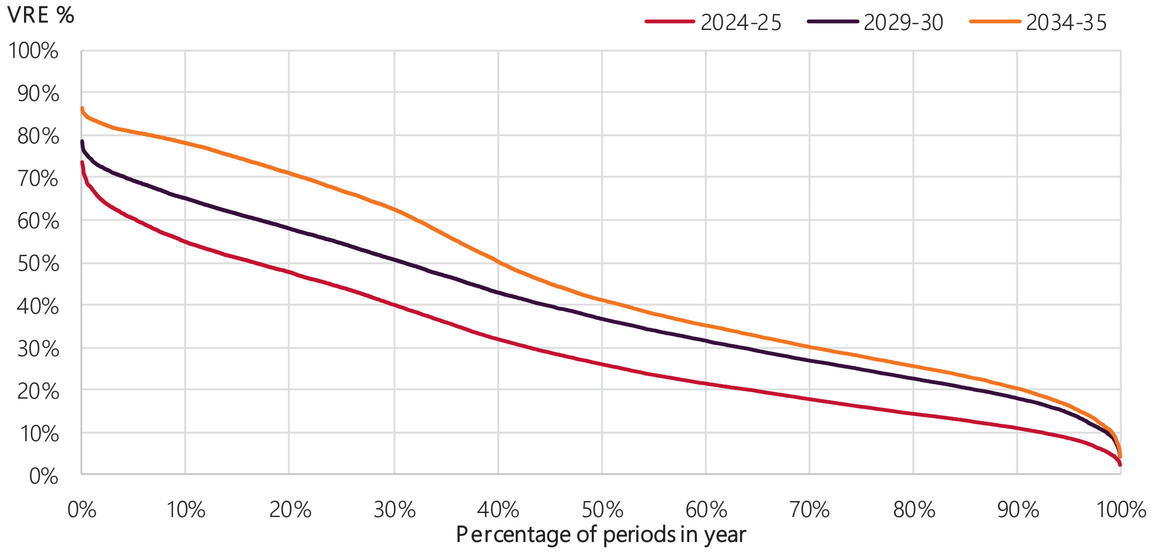
Part F
Projected ISP outcomes against objectives

As discussed in Section A2, the ISP's objective is to deliver both power system and broader policy needs through a complex transformation, in the long-term interests of electricity consumers[58]. It is therefore appropriate to set out the projected outcomes of the optimal development path, if it were fully implemented.

Power system transformation

The ISP re-confirms that the NEM power system will continue its significant transformation to world-leading levels of renewable generation. This will test the boundaries of system security and current operational experience. As identified in AEMO's Renewable Integration Study (RIS)[59], targeted actions can overcome regional and NEM-wide challenges to allow the NEM to be operated securely with up to 75% instantaneous penetration of wind and solar. The RIS concluded that beyond 2025 – provided the recommended actions were undertaken *and* there are suitable investments in infrastructure to provide the required system services – the NEM could operate securely at even higher levels of instantaneous wind and solar penetration. This ISP forecasts that by 2035 there could be periods in which nearly 90% of demand is met by renewable generation: see Figure 27. It is therefore imperative that the recommended actions are completed and the market reformed to ensure the necessary system services are available when needed: see Appendix 7.

Figure 27 By 2034-35, renewable generation may at times deliver 85% of generation



58 Clause 5.22.3

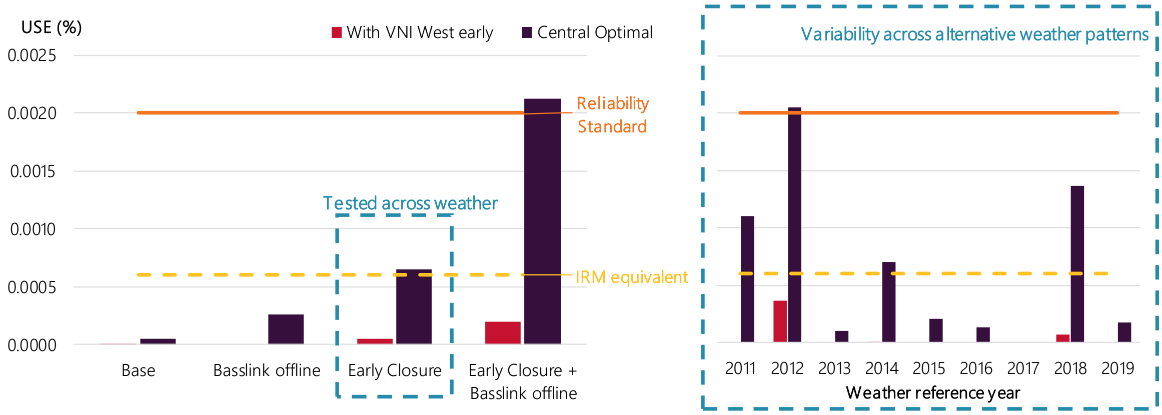
59 Stage 1 Report: https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris

Power system needs

The power system needs are the reliability and security requirements for operating a power system within operating limits and in accordance with operating standards, in particular following a contingency event.

All of the candidate paths are selected to ensure that these power system needs are met. Figure 28 shows the extent to which major market events, as well as weather-related and technical stresses, can test reliability. The reliability standard for the NEM is that unserved energy (USE) is less than 0.002% in any region, as shown by the chart's orange line. The explanation of how AEMO derives USE is provided in the methodology report[60] for AEMO's ESOO. In addition, the COAG Energy Council has set an expectation that the power system remains reliable during a 1-in-10 year summer, introducing an Interim Reliability Measure of 0.0006% expected USE, plotted here as a dashed line, as an interim measure ahead of a more enduring market design being developed.

Figure 28 Reliability and IRM standards are met, with VNI West in place



The left-hand chart shows how market events – in this case an early closure of Yallourn while Basslink is offline – can push grid reliability over those limits. The right-hand side shows the reliability standard not being met if the early closure combines with a 1-in-10 year weather event, and the IRM equivalent limit being exceeded on multiple occasions. In both cases, there is less likelihood that AEMO would need to enter into costly reserve contracts to cover supply scarcity risks if VNI West is available before Yallourn retires.

Competition and affordability policies

The ISP must also address affordability, competition and consumer choice issues, within the limits set by its Rules.

Affordability is pursued by the rigorous pursuit of the least-cost development path under each scenario, and the selection of an optimal development path that balances that cost outcome with the need for power system security and reliability.

Lower consumer bills are the product of these total system costs, effective regulation and effective market design for unregulated investments. Accordingly, the least-cost development path assumes

[60] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2016/2016-NEM-ESOO-Methodology.pdf

market arrangements are in place to support the most cost-effective solutions to the NEM's security and reliability needs. In fact, the ISP assumes perfect markets.

If those market arrangements are in place, the energy market will remain competitive and spur the range of dispatchable solutions shown in Figure 29. In any case, the optimal development path protects consumers from significant costs associated with not having adequate resources available to deliver affordable and reliable electricity, delivering over $7 billion in net market benefits in Central scenario (see Figure 30), and over $11 billion averaged across the scenarios.

Figure 29 The optimal development path secures the full range of competitive energy resources

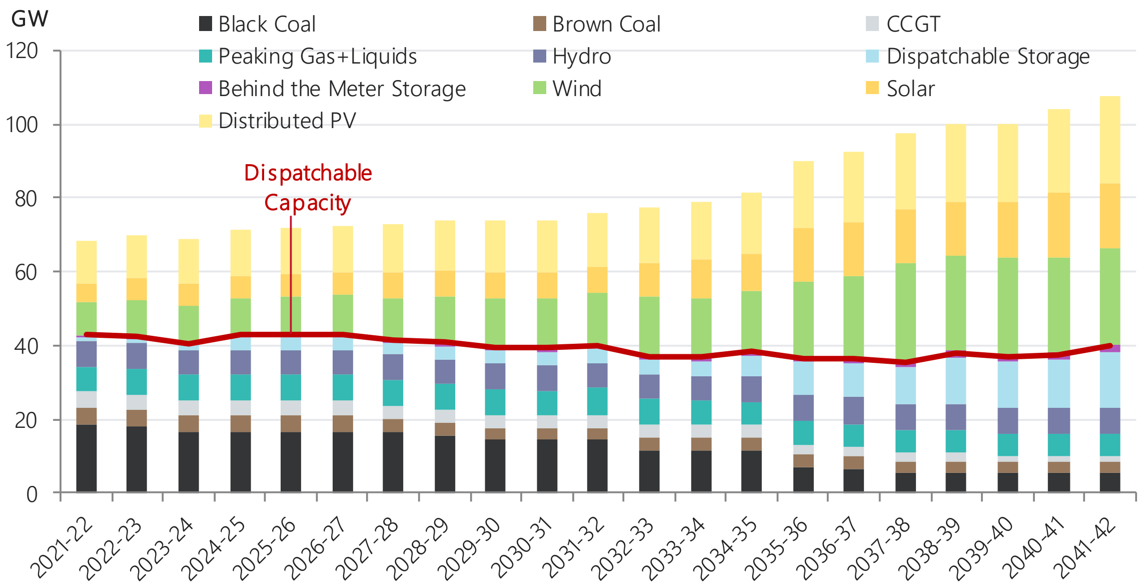
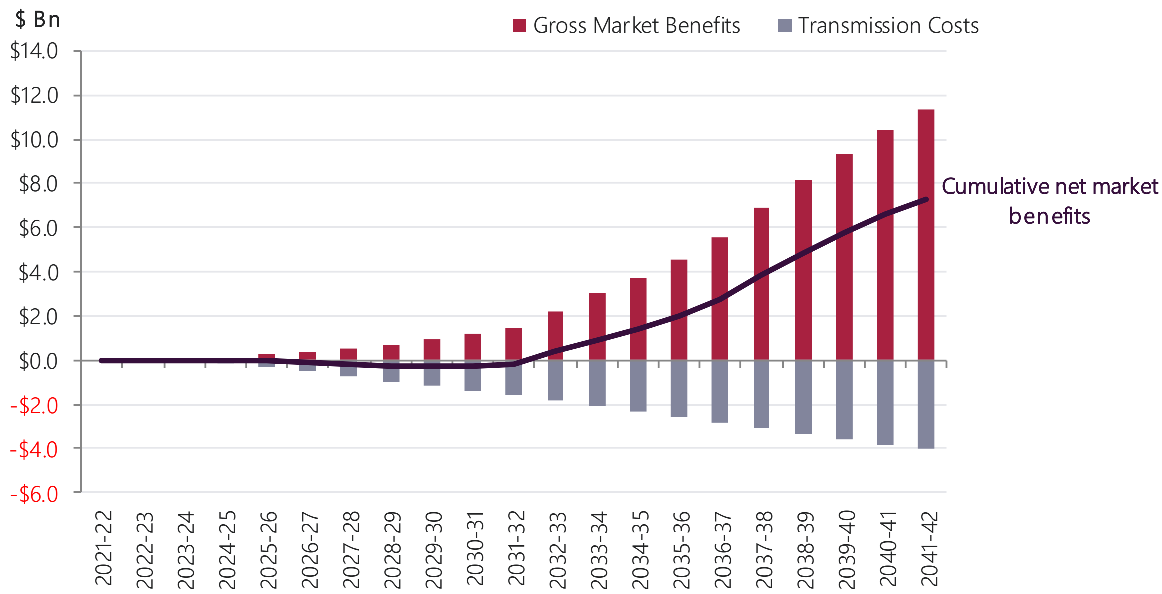


Figure 30 Significant savings are delivered by the optimal development path, Central scenario



Note: Based on DP8 outcomes.

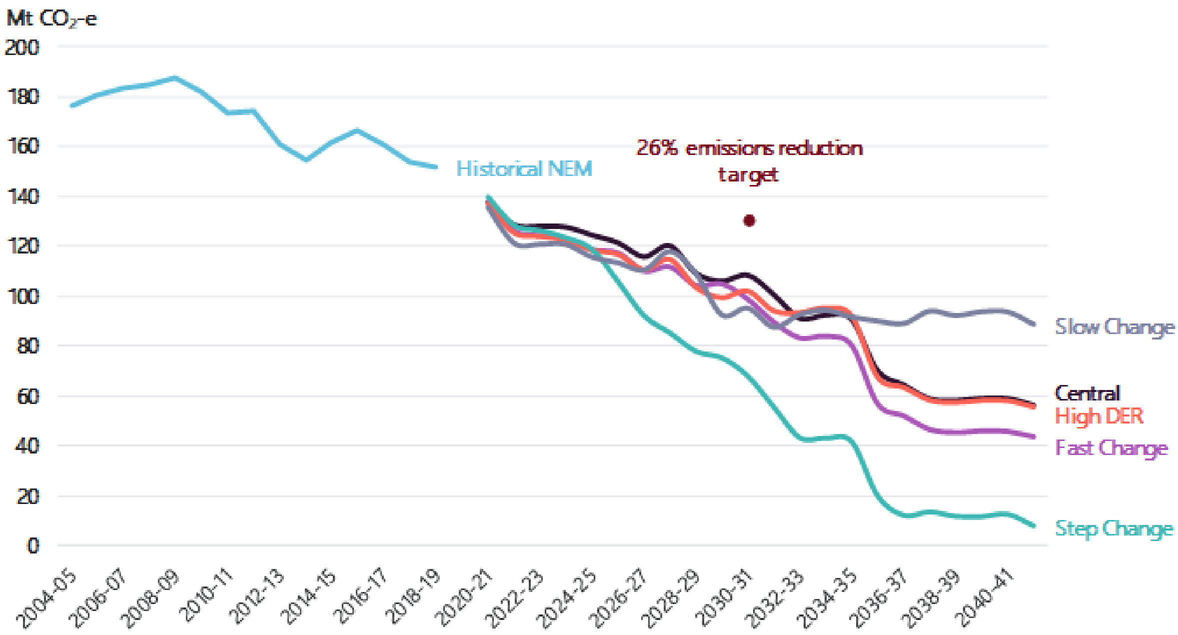
Emission and RET policies

The primary policies incorporated in the ISP are the existing state and federal environmental and energy policies affecting the energy sector, including emission reduction policies and state-based RETs, and state-based policies for REZs (New South Wales).

All these objectives are met by the optimal development path:

- **Australia's Paris Agreement target** is a 26% reduction in 2005-level emissions by 2030. This target is exceeded in the NEM under all scenarios: see Figure 31. However, beyond 2030, in the Central scenario, this is an outcome of investments made for economic, cost-benefit and risk management reasons, not explicitly for emission reduction.

Figure 31 Australia's emission reduction target is met under all scenarios



- **State-based RETs** range widely, depending greatly on the current level of renewable energy being generated. Most states and regions have set 2030 targets to support Australia's Paris Agreement target, ranging from 50% renewables in Victoria through to 100% in the Australian Capital Territory and Tasmania (noting that a new target may be legislated before year end): see Figure 32. The optimal development path would meet all these targets in all scenarios where these policies are included. However, Victoria's 2030 target can more easily be met with the early availability of VNI West, and Tasmania's 2040 target could only be reached with Marinus Link, despite the state's strong renewable resources: see Section E1.2 above.

Figure 32 RETs are met in most scenarios, with VNI West and Marinus Link available

* * *

This 2020 ISP is a dynamic, whole-of-system plan that identifies the optimal development path for regulated assets and development opportunities, as well as the complementary market reform needed to meet future power system needs efficiently and sustainably.

To implement this roadmap, multiple and well-co-ordinated efforts will be needed to progress DER, VRE, firming capability, transmission development, system security, gas development and market reform. And they will need to start now, given the long lead times for major projects, the scale of reform required, and the imminent end-of-life retirement of significant volumes of coal-fired generation.