The Health of the National Electricity Market

ENERGY SECURITY BOARD

Volume 2: Major Reports 2019, AEMC, AEMO and AER

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2019 AEMC Market Reviews and Rule Change Requests

C1. Retail energy competition review 2019

This annual review assesses competition in the small customer electricity and natural gas retail markets in all jurisdictions.

Retail competition reviews are conducted in accordance with the framework set out in the Australia Energy market Agreement. A range of information sources are used to form an evidence base to assess the state of competition against the following five competitive market indicators:

- the level of customer activity in the market
- customer satisfaction with market outcomes
- barriers to retailers entering, expanding or exiting the market
- the degree of independent rivalry
- whether retail energy prices are consistent with a competitive market.

The review shows bill reductions in most jurisdictions across the national electricity market. The competition review report also recommended funding for consumer and community organisations to help vulnerable consumers develop their energy literacy, including better understanding of financial schemes offered by retailers and governments.

C2. Residential electricity price trends 2019

This annual report identifies the cost components of the electricity supply chain that contribute to the overall price paid by residential consumers, and the expected trends in each of the cost components and consumer billing outcomes.

In 2020 the timeframes for the price trends reports changes to April and October each year. This timing provides information to governments ahead of the regular price changes from retailers in July and January. The revised price trends reports are shorter and more targeted, focusing on key findings and insights from the analysis.

The late 2019 report found that on a national basis, representative residential electricity prices and bills are expected to decrease over the period from 2018-19 to 2021-22, primarily driven by wholesale costs reducing in most of the states and territories. Prices fall markedly over the whole reporting period as new capacity enters the system. Total capacity of committed projects includes 2,338 MW of solar, 2,566 MW of wind and 210 MW of OCGT.

It also found that regulated network prices have been cut in response to falling distribution costs and environmental costs are being driven down by cheaper large-scale generation certificates for increasing levels of renewable generation.

C3. Coordination of generation and transmission investment

In 2016, the AEMC implemented a biennial reporting regime on changes that impact transmission and generation investment. The inaugural *Coordination of generation and transmission investment (COGATI) review* was completed in December 2018 and recommended key reforms to the current transmission access framework.

In March 2019 the AEMC started the second COGATI review. The current review has two key focuses – developing the specification of the proposed transmission access model, which implements dynamic regional pricing and financial transmission rights; and facilitating renewable energy zones. Renewable energy zones are a useful first step to more holistic access reform and can be a simpler, more discrete implementation than reforming the entire access regime.

In October two discussion papers were published, one setting out the detail of the proposed access reform model, and the other on renewable energy zones.

The current review will conclude and be given to the COAG Energy Council in March 2020.

The work done in the COGATI review is linked that the work being done with the Energy Security Board (ESB) to report back more broadly to the COAG Energy Council on REZ connections, access and congestion. In addition, the AEMC is also working with the ESB on its 2025 market design and actioning the ISP work.

C4. Electricity network economic regulatory framework review 2019: integrating distributed energy resources for the grid of the future

The AEMC published this report in September 2019. This report monitors market developments on an annual basis. It considers whether economic regulation of electricity networks is sufficiently robust and flexible to support the long-term interests of consumers in a future environment of increased decentralised energy supply.

The 2019 final report was split into two; integration of distributed energy resources and regulatory sandbox arrangements to support proof-of-concept trials (See the section on regulatory sandbox arrangements).

A range of options was set out to create more dynamic markets and manage network challenges as the penetration of distributed energy resources increases. It highlights work that is already underway to implement distributed energy resources effectively, what we are planning to do next, and whether we see any gaps.

C5. Review of the regulatory frameworks for stand-alone power systems

The AEMC considered the regulatory framework required to allow local distribution networks to use stand-alone power systems where it is economically efficient to do so. At the same time appropriate consumer protections and service standards were to be maintained. The review also considered the regulation needed for stand alone power system that are provided by parties other than local distribution networks.

The terms of reference set out two priority areas of work:

- Priority 1 – develop a national framework to facilitate the transition of grid-connected customers to a stand-alone power system supply provided by the current distribution networks, and a mechanism for the transition of grid-connected customers to a third party stand alone power system supplier
- Priority 2 – develop a national framework for the ongoing regulation of third party stand-alone power systems.

The AEMC has recently commenced a program of work to develop the detailed rules required to implement the recommendations made in the stand alone power system priority 1 final report. A draft report for this investigation was published in December 2019.

C6. Regulatory sandbox arrangements to support proof-of-concept trials

The AEMC recommended the introduction of a regulatory sandbox toolkit in the national energy markets in a final report in September 2019. The new arrangements make it easier for businesses to develop and trial innovative approaches to providing energy services to consumers.

A regulatory sandbox is a framework where participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.

The recommended regulatory sandbox toolkit has been designed to be used sequentially. It includes an innovation enquiry service, regulatory waivers and trial rule changes.

The AEMC has prepared recommended drafting instructions for amendments to the national energy laws. The AEMC has also provided initial drafting for changes to the national energy rules to give effect to the toolkit.

In November 2019, the COAG Energy Council agreed to the AEMC's recommendations to introduce a regulatory sandbox toolkit. The Council will develop draft law changes and conduct separate stakeholder consultation before law changes are submitted to the South Australian Parliament.

The Council also agreed to make changes to the National Electricity Rules (NER), National Energy Retail Rules (NERR) and the National Gas Rules (NGR) for regulatory sandbox arrangements, following the passage of law changes.

C7. Annual market performance review 2018 (published April 2019)

The annual market performance review covering the 2017-2018 period detailed the security implications attached to rapid change in the power system’s generation mix, with the power system only meeting consumers’ needs because AEMO used built-in safety nets on a daily basis to keep the lights on. These are expensive stop-gap measures that are not meant to be used regularly.

The final shows falling system strength at the fringes of the grid in north Queensland, south-west NSW, north-west Victoria and continuing weakness in South Australia. In 2017-2018 AEMO issued 100 directions to keep the system stable in South Australia, compared with only eight in 2016-2017.

The Panel will monitor and review how AEMO and the AEMC’s security and reliability work programs progress, with a view to recommending in the 2019 annual market performance review whether any further work remains to be done or if there are key issues that need to be addressed.

C8. Review of the System Black Event in South Australia on 28 September 2016

Following the black system event of 28 September 2016, the AEMC undertook a review, the purpose of which was to identify and report on any systemic issues that contributed to, or affected the response to, the black system event in South Australia. The report was provided to the COAG Energy Council following the completion of both the AER compliance and the AEMO incident reports.

The AER commenced legal proceedings in mid-2019 against a number of generators in relation to their compliance with the National Electricity Rules during the events of 28 September 2016. The AEMC's review focusses on the period immediately leading up to the black system event, as well as the period of system restoration and market suspension that followed the event.

The final report included recommendations designed to enhance the resilience of the power system. The AEMC has proposed to:

- give AEMO greater flexibility to protect the system from severe disturbances, such as major storm systems that threaten an entire region
- create a new risk review process to allow AEMO, networks and market participants to work together to identify new risks and develop solutions
- provide AEMO with flexibility to prioritise system security actions during a period of market suspension.
- a final report in December 2019, includes proposed rule drafting.

C9. Last resort planning power – 2018 review

The last resort planning power is an oversight mechanism conferred on the AEMC to complement the planning roles of AEMO, as national transmission planner, and transmission network companies.

It allows the AEMC to require network companies to consider and consult on options to alleviate constraints on the interconnected transmission network when these companies have not initiated this process themselves. After reviewing system planning reports prepared by AEMO and transmission businesses, the AEMC confirmed there was no need to exercise the last resort planning power for 2018.

The AEMC also noted that regulatory processes are already underway for all Group 1 projects and some Group 2 projects that were prioritised in AEMO's Integrated System Plan.

C10. Updating the regulatory frameworks for embedded networks

The AEMC published a final report for its review into *Updating the regulatory frameworks for embedded networks* to implement a new regulatory regime for embedded networks in June 2019. The final report recommends detailed amendments to national energy laws and rules that would establish a new regulatory regime to improve consumer protections and access to retail market competition for embedded network customers.

The COAG Energy Council's Senior Committee of Officials has established a working group to progress recommendations from the *Review of the regulatory framework for stand-alone power systems –priority 1* and *Updating the regulatory framework for embedded networks*. The AEMC will liaise closely with the working group to progress this work.

C11. Investigation into intervention mechanisms and system strength in the NEM

The AEMC initiated this review of the interventions framework in April 2019 in light of the growing number of directions being issued by AEMO to maintain system strength and the recent use of the Reliability and Emergency Reserve Trader mechanism.

A final report was published in August about the regulatory frameworks that govern the use of interventions in the NEM, together with two draft determinations on related rule change requests.

The AEMC is also considering whether improvements can be made to the minimum system strength and inertia frameworks in the rules to more effectively and efficiently identify and address shortfalls in system strength and inertia as they arise in NEM regions. The AEMC will progress this work in 2020.

Further work was also completed on the: Reliability and Emergency Reserve Trader

Together with the three determinations that followed this work, and a further report several changes to the interventions framework were recommended. These covered:

- Compensation for directed participants
- Compensation for affected participants
- Hierarchy of intervention mechanisms
- Counteractions; and
- Mandatory restrictions

C12. Wholesale demand response

On 18 July 2019, the AEMC released a draft rule determination setting out a series of changes to the rules to facilitate wholesale demand response in the NEM, principally through implementing a wholesale demand response mechanism.

The rule change process was extended in December to consider how the mechanism fits with the design of two-sided market. The AEMC expects to release a second draft determination in March 2020, followed by a final determination in June 2020.

C13. Short term forward market

The AEMC received a rule change request from the AEMO proposing introducing a voluntary short term forward market so participants can contract for electricity in the week leading up to dispatch.

The AEMC proposed not to make the draft rule as it was unlikely it would contribute to the national electricity objective. The conclusion from the consultation and market analysis was that there is currently limited demand for short term hedge products in the market and that demand is sporadic and bespoke. The AEMC expects to publish a final determination in March 2020.

C14. Market making arrangements in the NEM

Market making arrangements aim to increase the opportunities for market participants to trade in electricity hedge contracts and to have greater visibility of wholesale contract prices. They can be voluntary or compulsory.

In September the AEMC decided not to make a rule to introduce additional market making schemes in the national electricity market. This is because a number of initiatives are already underway that should increase contract market liquidity - in particular the ASX's voluntary market making scheme and the market liquidity obligation that is part of the Retailer Reliability Obligation.

In making the draft determination on ENGIE's request to establish a tender for voluntary market making services, the AEMC found that additional market making arrangements beyond the ASX and market liquidly obligation initiatives would ultimately add costs for consumers while being unlikely to provide any additional benefits.

C15. Demand management incentive scheme and innovation allowance for TNSPs

In December 2019 the AEMC published a final determination and a more preferable final rule to apply an innovation allowance to transmission networks.

Introducing the demand management innovation allowance as proposed by Energy Networks Australia (ENA), will encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that may reduce long term network costs – which could ultimately lower electricity bills for consumers.

ENA also proposed to extend the demand management incentive scheme to transmission. However, the AEMC was not satisfied that the benefits of applying the demand management incentive scheme would outweigh the upfront costs to consumers. If the demand management incentive scheme was implemented, transmission businesses would receive incentive payments for undertaking non-network options that they would already have been required to adopt under the regulatory investment test for transmission.

C16. Primary frequency response rule change requests

In December 2019 the AEMC made a draft rule to require all scheduled and semi-scheduled generators in the NEM to support the secure operation of the power system by responding automatically to changes in power system frequency.

The draft rule is designed to address an immediate need for improved frequency control which has been identified by AEMO. The draft rule is intended to commence on 4 June 2020 and sunset after 3 years on 4 June 2023.

This draft determination relates to two rule change requests,

Key aspects of the draft rule include:

- all scheduled and semi-scheduled generators, who have received a dispatch instruction to generate to a volume greater than 0 MW, must operate their plant in accordance with the performance parameters set out in the Primary frequency response requirements as applicable to that plant
- AEMO must consult on and publish the Primary frequency response requirements, which will specify the required performance criteria for generator frequency response, which may vary by plant type
- generators may request and AEMO may approve variations or exemptions to the Primary frequency response requirements for individual generating plant.

This rule change is part of our Frequency control work plan which sets out a series of actions that AEMO, the AEMC and the AER are undertaking to review and reform the frequency control frameworks in the national electricity market.

The application of a mandatory obligation on generators to provide primary frequency response addresses the immediate system security needs of the power system. However, a mandatory requirement for narrow band primary frequency response is not a complete solution and, on its own, will not incentivise the provision of primary frequency response. Further work needs to be done to understand the power system requirements for maintaining good frequency control. This work should also consider the appropriateness of the mandatory requirement for narrow band primary frequency response and other alternative and complementary measures, including the potential for new market and incentive-based mechanisms for frequency control.

The draft determination includes an updated draft frequency control work plan developed in collaboration with AEMO. The work plan sets out a pathway for the development of future arrangements to appropriately incentivise and reward frequency control in the NEM. The AEMC will continue to work with the ESB, AEMO and the AER on these matters.

C17. Monitoring and reporting on frequency control and FCAS market outcomes

In July 2019, the AEMC made a final rule which establishes ongoing reporting requirements on AEMO and the AER in relation to frequency and market ancillary service performance. This rule change increases transparency and consistency of information provided to the market and was a key recommendation arising from the AEMC's *Frequency control frameworks review* in July 2018.

The key features of the final rule are:

- a requirement for the AER to report quarterly on each FCAS market, as well as provide an analysis of key trends and outcomes in each FCAS market
- a requirement for AEMO to report weekly on key frequency performance metrics as well as on the amount and utilisation of regulation FCAS
- a requirement for AEMO to report quarterly on frequency performance against the frequency operating standard.

C18. Transmission loss factors

The AEMC received two rule change requests seeking changes to the transmission loss factors framework in the national electricity market. Transmission loss factors are calculated by AEMO to reflect the electricity lost as heat when power is transported across the network.

In November the AEMC published a draft determination to keep the existing marginal loss factor methodology for calculating electricity lost during transmission, rather than moving to an average loss factor methodology. A final determination is due in 2020.

C19. Intervention compensation and settlement processes

The AEMC made a rule in May 2019 to improve administrative processes related to compensation and settlement, following an AEMO intervention in the market.

This new rule aligns the timetables for compensation and settlement following an intervention, streamlining the process used for recovering associated costs and increasing the transparency and consistency of the processes that AEMO needs to administer. It also extends the deadline for participants to make additional claims, which will allow participants more time to assess the impact of intervention events.

C20. Transparency of New Projects

On 24 October 2019 the AEMC made a final rule to improve publicly available information about new grid-scale generation projects. The rule also allows a broader set of project developers direct access to important system information required to build grid-scale assets.

The final determination improves information provision for new generation projects in the national electricity market (NEM).

The final rule:

- facilitates greater access to relevant system information for developers that sell grid-scale assets prior to connection, while recognising that certain types of developers can already access this information by registering as intending participants
- codifies AEMO's generation information page in the National Electricity Rules. The page is an information resource that provides a source of regularly updated data on existing and proposed generation connections to the national grid.
- requires transmission network service providers to share basic connection information about new generation projects with AEMO. AEMO then publishes this data on the generator information page.
- The final rule supports the energy market transition by making it easier and quicker for developers to assess the viability of proposed projects. The final rule also means market participants are better informed of proposed connections which may assist them with their operational and investment

Key dates for the implementation of the rule are:

- From 19 December 2019: Developers are able to apply to access relevant system information under new arrangements.
- From 19 December 2019: Key connection information provided as part of a connection enquiry or application (for a generating plant) that is submitted on or after this date must be shared by transmission networks with AEMO.
- By 31 January 2020: AEMO is required to publish its generation information page. This time frame allows AEMO time to publish interim guidelines that set out the content of the generation information page and how it will be updated. Transmission networks will have at least two weeks to process AEMO's interim guidelines before being required to comply with their new information sharing obligations.

C21. Early implementation of ISP priority projects

In April 2019 the AEMC released a final determination to streamline the regulatory process for three priority projects identified in AEMO's Integrated System Plan (ISP). The plan has a list of priority transmission projects which includes upgrades to the interconnectors joining QLD-NSW and VIC-NSW, and a new interconnector between South Australia and New South Wales (EnergyConnect).

The new rules allow the AER to concurrently consider regulatory processes that apply to the three projects after the completion of the regulatory investment test. The final rule does not remove or change any of the regulatory steps for these projects other than to allow them to run concurrently, and the AER cannot complete a step until the previous step has been completed.

C22. Enhancement to the Reliability and Emergency Reserve Trader

In May 2019, the AEMC released a final determination for the reliability and emergency reserve trader – the emergency mechanism used when the power system is under extreme pressure.

Using emergency reserves more frequently means higher costs associated with the RERT making their way onto consumer bills. This new rule enhanced the emergency reserve framework to provide AEMO with the flexibility it needs to meet the operational challenge arising from the restructure of the generation sector – at the lowest possible cost to consumers.

C23. Five minute settlement and global settlement implementation amendments

In August 2019 the AEMC published a final determination to amend nine areas of the National Electricity Rules (NER) to help implement five minute settlement and global settlement. The changes improve wholesale market operations under five minute settlement, clarify global settlement arrangements and improve information provision requirements.

C24. Application period for contingent project revenue

In April, the AEMC released a final determination to remove barriers so that network businesses can speed up their investments in time-critical projects.

Contingent projects are major network infrastructure assets, flagged in network revenue proposals and approved by the AER in revenue determinations. Network businesses can now submit a contingent project application at any time during a regulatory control period up until the last 90 business days of the period's second last year. This change may result in the earlier implementation of transmission and distribution projects, including time-critical projects while maintaining the intent of the framework – to achieve efficient outcomes for consumers through investment in network projects.

C25. Metering installation timeframes

In December 2018 the AEMC published a final determination that gives customers more control over when their retailer installs or upgrades their electricity meter. The new rule commenced on 1 February 2019.

Retailers will now have to install new, replacement or upgraded smart meters at a time agreed with customers or, if agreement cannot be reached, within a specified timeframe. The rules also place new obligations on network businesses to notify retailers as soon as they have finished connection work for a customer so the meter can be installed promptly.

The AEMC has recommended the COAG Energy Council approve new civil penalties to protect customers if retailers or network businesses do not meet these new deadlines.

C26. Meter installation – advanced meter communications

In March 2019 the AEMC released a final determination that makes provision for customers to request their metering coordinator to deactivate a smart meter's communications even when it has already been installed. Accepting a customer's objection to the use of a smart meter is at the discretion of the metering coordinator.

Under the AEMC's competition in metering rules, which started in December 2017, all new and replacement meters for small customers must be smart meters.

At the time of installation, customers are entitled to request that the smart meter's communications are deactivated which means that the meter can no longer be read remotely or provide smart functions like demand response.

More information is available on all these AEMC matters on the AEMC website.

2019 AEMO Major Reports

D1. AEMO Renewable Integration Study

Maintaining Power System Security with High Penetrations of Wind and Solar Generation - International insights for Australia[1]

October 2019

The transformation of the power system is presenting new engineering challenges that must be addressed. Since Australia is leading in many regards in its increase in wind and solar, it is incumbent upon AEMO to understand the challenges and put solutions in place before they impair operations.

AEMO's Integrated System Plan (ISP)[2] articulates a whole-of-system development pathway for the National Electricity Market (NEM), to design and execute the transition in a way that maximises benefits at lowest cost and risk to consumers. AEMO develops a range of future scenarios in the ISP to evaluate the potential changes that can occur on the power system, and to identify no regrets investments that can be made to provide the best outcome for consumers.

In addition to the ISP, AEMO conducts further analysis where there is merit in a deeper level of inquiry, including analysis of those technologies that are at the forefront of the transformation. AEMO has published several reports into the changing generation mix[3], including a recent study into storage as a significant component of the modern integrated power system[4] and an analysis of the implications of residential and commercial solar penetration in the Western Australian South West Integrated System (SWIS)[5].

As a supplement to developing the 2020 ISP, AEMO commenced the Renewable Integration Study (RIS)[6] to take a deeper review into the specific system implications and challenges associated with the integration of large amounts of variable inverter-based renewable generation and decentralised energy in the NEM power system.

AEMO's Power System Requirements reference paper presented an overview of the specific requirements of the power system[7]. The RIS builds on that paper, to explore the specific

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[1] See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf

[2] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[3] Appendix A.3 provides a summary of relevant past AEMO publications into the changing generation mix.

[4] AEMO, ISP Insights – Building power system resilience with pumped hydro energy storage, July 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Insights---Building-power-system-resilience-with-pumped-hydro-energy-storage.pdf.

[5] AEMO, Integrating Utility scale Renewables and Distributed Energy Resources in the SWIS, March 2019, at https://www.aemo.com.au/-/media/Files/Electricity/WEM/Security_and_Reliability/2019/Integrating-Utility-scale-Renewables-and-DER-in-the-SWIS.pdf.

[6] AEMO, Renewable Integration Study, July 2019, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study.

[7] AEMO, Power System Requirements, March 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

opportunities and risks for maintaining the physical requirements of the power system while integrating variable inverter-based renewable resources at increasing levels of penetration. This in-depth review will inform future ISPs as well as providing foundational engineering advice to government and administrative policy-makers to support their consideration of future changes needed in electricity regulations and market designs.

The RIS is being undertaken in a series of steps:

1. A review of leading international experience in wind and solar photovoltaic (PV) integration[8].
2. Detailed analysis of phenomena specifically related to wind and solar PV technologies[9].
3. Presenting a view of what operating the NEM could look like over the next decade.
4. Engaging with local and international organisations and independent experts to review and collaborate on AEMO's preliminary findings.
5. A final report in March 2020 into the technical challenges and possible system limits associated with integrating increasing levels of variable inverter-based resources, and a roadmap of priorities to manage these challenges.

In the first step, AEMO supplemented previous studies with a review on how Australia compares to similar international power systems. The objectives of the international review are:

- First, comparison of the technical challenges that Australia has experienced or identified with the experience of other jurisdictions to reveal any previously undetected challenges.
- Second, to update understanding of how these other jurisdictions are managing the technical requirements of their power systems during the transformation, and what practices appear effective from a technical perspective.
- Third, evaluating these various approaches to see if there are lessons that can be applied to achieve better outcomes in Australia's NEM and SWIS.

AEMO stresses that the international review is to help inform potential approaches to current and emerging technical challenges, not necessarily to prescribe specific approaches that have worked overseas. Although the physics underlying power system operation are universal, the need for a particular solution is impacted by different features of each system, including the level of interconnection with adjacent systems, geographic size, generation mix, and local climate conditions. Prevailing regulatory and market design considerations also influence how any necessary requirements can be most effectively implemented in a particular jurisdiction.

Key findings of International Review

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[8] See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf

[9] The study uses a projected generation mix and network configuration in 2025 as a focus for its detailed analysis. 2025 was chosen as the focus for the first stage of the RIS to enable more detailed focus and increase confidence and certainty in outcomes of power system models, because AEMO has a reasonable level of information about the generation projects that might be connected out to 2025.

The international review has identified five key insights, which are summarised below and explored in more detail below:

1. Parts of Australia are already experiencing some of the highest levels of wind and solar generation in the world, including one of the highest levels of residential solar PV.
2. Successfully integrating high levels of DER requires an increasing level of visibility, predictability, and controllability of these small distributed devices. Australia can learn from several jurisdictions in its approaches to these challenges.
3. Managing variability and uncertainty is increasingly challenging at higher levels of wind and solar generation. Australia can learn from others in their approaches, including the assessment of system ramping requirements and fleet capability.
4. Australia should consider international approaches to frequency management in high renewable generation systems, including approaches to maintaining sufficient inertia and enablement of primary frequency response on all generators.
5. International power system operators have taken a staged approach to operating power systems with progressively less synchronous generation online. A similar approach could be considered in Australia.

- Parts of Australia are already experiencing some of the highest levels of wind and solar generation in the world, including one of the highest levels of residential solar PV.
- Synchronously interconnected[10] power systems have operated for periods where wind and solar energy was larger than demand – including Denmark (157%) and South Australia (142%).
- Island power systems[11] have operated at high levels of wind and solar generation relative to demand – Ireland (85%), Tasmania (70%), and Great Britain (67%).
- Australia is achieving these very high levels while at the forefront of connecting wind and solar generation in areas with low system strength[12].
- Australia has one of the highest penetrations of residential solar in the world (20% of homes). The most comparable international system, in terms of both the penetration and impact of residential solar on system operation, is the island of Oahu in Hawaii.

Successfully integrating high levels of DER requires an increasing level of visibility and controllability of these small distributed devices. A minimum level of predictable performance during power system disturbances is also needed. Australia can learn from several jurisdictions in their approaches to these challenges, and how these approaches can benefit consumers.

- Lack of visibility of DER compromises the system operator’s ability to understand their behaviour and appropriately manage the power system. The Electric Reliability Council of Texas (ERCOT) has taken steps to collect static information about DER installed on its networks and integrate this information in its power system models. New regulations have been introduced in the NEM mandating collection of static device information of all DER[13], and AEMO is in the process of developing updated

[10] Synchronously interconnected systems are connected to other power systems via alternating current interconnectors.

[11] Island power systems are either not interconnected or are interconnected using high voltage direct current.

[12] See Section 3.5 for a discussion of system strength.

[13] See https://www.aemc.gov.au/rule-changes/register-of-distributed-energy-resources.

load models[14]. Other jurisdictions have the advantage of a level of real-time operational visibility of significant portions of their DER fleet (for example, 70% of small-scale PV in Germany and Italy are commercial systems with telemetry). Currently AEMO and Australian distribution network service providers (DNSPs) have limited to no real-time visibility of PV systems less than 5 megawatts (MW).

- As passive DER increases, system operators' controllability of the power system reduces. EPRI found that control of DER is often the most cost-effective, and potentially the only, solution to ensure security[15]. Some form of feed-in management over a large fleet of residential solar PV systems has been implemented by system operators in Germany, Japan, and Hawaii, but so far these are only intended for isolated emergency situations. The NEM and SWIS do not currently have any means to actively control residential DER, even in emergency situations.
- Recognising the system impacts of increasing penetrations of residential PV, several jurisdictions have recently mandated improved inverter functionality for small-scale PV systems. In Europe, this has been through national level implementations of the European Network Code for Generators introduced in 2016, most notably Germany and Denmark. In the US, California and Hawaii updated their own local requirements in 2016, which in 2018 were integrated within the US national standard for DER connection. AEMO is leveraging learnings from international standards development, and in collaboration with DNSPs and local industry, is progressing the introduction of similar requirements in Australia.

Managing variability and uncertainty is increasingly challenging at higher levels of wind and solar generation. Australia can learn from others in their approaches, including the assessment of system ramping requirements and fleet capability.

- EUSysFlex – a large cooperative program of work in Europe – identified a likely reduction in system flexibility if variable generation displaces conventional generation in an uncoordinated way16. California has seen a steady drop in midday demand due to high levels of installed solar generation, creating a large ramp up to the evening peak17.
- To ensure a sufficient amount of system flexibility is available to cover renewable variability, Ireland and California have implemented ramping constraints that interface with their scheduling process. The constraints account for uncertainty in demand, renewable generation (utility and distributed), and conventional generation.
- AEMO is undertaking detailed analysis as part of the RIS to understand how ramping challenges are likely to emerge in the NEM with increasing levels of variable wind and solar generation. Of particular focus will be quantifying how system variability changes as more variable generation is installed, and the level of inherent uncertainty in forecasting the output of these generators on any day.

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[14] AEMO, Technical Integration of DER Report, pages 63 and 64, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf.

[15] EPRI International Review on Opportunities to Activate DER, at https://aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Standards-and-Protocols.

[16] EUSysFlex Literature Review , accessed 11 September 2019, at http://eu-sysflex.com/wp-content/uploads/2018/12/D2.1_State-of-the-Art_Literature_Review_of_System_Scarcities_at_High_Levels_of_Renewable_Generation_V1.pdf.

[17] See https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

Australia should consider international approaches to frequency management in high renewable generation systems, including approaches to maintaining sufficient inertia and enablement of primary frequency response on all generators.

- In Texas and Ireland, primary frequency response (PFR) is required from conventional and renewable generation in response to small and large disturbances. The SWIS shares this requirement, but the NEM does not – only a subset of available generation is required to respond to larger disturbances, when selected by the market. AEMO has recently recommended changes to the regulatory framework in the NEM to require PFR from all generators[18].
- Texas and Ireland have employed inertia requirements that are applicable at all times. Similarly, Great Britain and Ireland have employed rate of change of frequency (RoCoF) requirements that apply at all times. The NEM currently has select inertia and RoCoF requirements that are only active under certain circumstances.

International power system operators have taken a staged approach to operating power systems with progressively less synchronous generation online. A similar approach could be considered in Australia.

- Of the operators surveyed, EirGrid (Ireland and Northern Ireland) is taking a staged approach to relaxing power system operational limits related to minimum numbers of synchronous generators online.
- Consideration should be given to how new system conditions can be trialled safely in the NEM and SWIS. This could include taking a precautionary approach (such as mitigating risks and holding extra reserve) for a period (for example, one year) while the system is operated closer to its limits (for example, with fewer synchronous generators online) to build experience and confidence, before accepting those conditions as a new norm.

[18] At https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

D2. Electricity Statement of Opportunities (ESOO)

The *Electricity Statement of Opportunities* (ESOO) forecasts electricity supply reliability in the National Electricity Market (NEM) over a 10-year period. The ESOO also includes the reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO)[1].

The 2019 ESOO forecasts a continued elevated risk of expected unserved energy (USE)[2] over the next 10 years.

Key findings

Summer 2019-20

- AEMO forecasts tightly balanced supply and demand in several NEM regions for summer 2019-20, with all regions other than Victoria expected to meet the current reliability standard of expected USE not exceeding 0.002%.
- In Victoria, if extended into the peak summer period, the unplanned outages of two major power stations, Loy Yang A2 (500 megawatts [MW]) and Mortlake 2 (259 MW), pose a significant risk of insufficient supply that could lead to material involuntary load shedding. AEMO is working with industry to secure the maximum permissible reserves via the Reliability and Emergency Reserve Trader (RERT) to ensure Victoria's reliability of supply meets the reliability standard this summer. AEMO is being supported to meet its responsibilities by the Victorian Government.

Forecasts beyond 2020

- Beyond 2020, AEMO forecasts only slight improvements in reliability for peak summer periods until new transmission and dispatchable supply and demand resources become available. AEMO's 2019 ESOO reaffirms the message in the 2018 ESOO that additional investment will be required in a portfolio of resources ahead of time to replace retiring capacity.
- The 2019 ESOO analysis includes nearly five gigawatts (GW) of committed new generation projects and upgrades to existing generators expected to become available over the next three years, in addition to Snowy 2.0 (2,040 MW), which has been assumed to be fully operational by March 2025.
- Most of the announced new generation projects are variable renewable energy generators, which often do not generate at full capacity during peak demand times or may be positioned in a congested part of the network. As a result, while providing significant additional energy during many hours of the year, these projects are forecast to only make a limited contribution to meeting demand during peak hours

Impact of Liddell closure 2022-24

- AEMO forecasts that the level of USE in New South Wales will increase following the gradual closure of Liddell Power Station, but remain slightly below the current reliability standard, reaching 0.00174% USE in 2023-24 after Liddell's full closure. This analysis presumes no new investments in generation, transmission, or demand response, beyond what is already committed. It specifically does not include the benefits of the Queensland to New South Wales Interconnector (QNI) and the Victoria to New South Wales Interconnector (VNI) projects, because both projects are yet to receive full regulatory approval. Governments, the Energy Security Board

(ESB), and the Australian Energy Regulator (AER) are working proactively on delivering both projects before the Liddell closure.

Required actions

AEMO has identified a number of prudent and least-cost actions that should be taken to avoid consumer exposure to an unreasonable level of risk of involuntary load shedding during peak summer periods. Some of these actions are currently underway and should be pursued without unnecessary delay. Others will require changes to rules and/or additions to AEMO's authority. AEMO will seek to implement these recommendations through its continued work with the Commonwealth and State Governments, the ESB, the Australian Energy Market Commission (AEMC), and the AER.

1. Summer readiness plan – as it does every year, AEMO is already working proactively with industry and governments to prepare for the coming summer by implementing a comprehensive summer readiness plan to minimise risks as much as possible within the current rules framework. This year, AEMO is also working in depth with generators and industry experts to gain a better understanding of forced outage rates of aging generators to improve future reliability assessments, in particular in light of the increasing frequency of hard to predict but high impact events such as unplanned outages of dispatchable supply resources.

2. Commissioning of targeted transmission augmentation – the supply-demand balance in New South Wales will be significantly improved with the addition of the QNI and the New South Wales component of the VNI upgrades and, once completed, through HumeLink and EnergyConnect, as identified in the 2018 ISP. This ESOO reconfirms the importance of the work now underway to complete QNI and VNI ahead of the closure of Liddell Power Station, involving significant undertakings by governments, industry, the ESB, and the AER. To enhance the resilience of the NEM against the growth of systemic risks during the energy transition (for example, to enable the system to absorb the impact of deteriorating performance of aging plants), a new mechanism will be required for the fast-tracked delivery of 'no regrets' transmission infrastructure and transmission infrastructure that could deliver important reliability and resilience benefits. The 2019-20 ISP will identify essential 'no regret' and resilience projects, and AEMO will work with governments, industry, market bodies, and the ESB to develop a process by the end of 2019 to implement them.

3. Dispatchable resources – once the above transmission infrastructure is in place, AEMO's analysis projects that new dispatchable supply of approximately 215 MW would be required to ensure New South Wales only has a one-in-10 year risk of a significant involuntary load shed event in summer 2023-24, following the full closure of Liddell Power Station. Over the coming two months, AEMO will work with industry and governments to identify the attributes and location of dispatchable resources that will address this risk and available mechanisms to assure the necessary investment.

4. Reliability standard – the current reliability standard is based on the expected USE within a given financial year not exceeding 0.002%. Because applying this standard requires the averaging of annual USE over all possible outcomes, it effectively averages out the risk of experiencing the rapidly growing number of events which can cause severe load shedding over the summer period. While AEMO has attempted to 'operationalise' the risks within the existing standard as much as possible, a modified reliability framework that enables AEMO to ensure customers are not exposed to significant involuntary load shedding in nine out of 10 years is necessary. AEMO will accordingly pursue the development of a modified standard over the coming three months that can more cost-effectively and reliably provide the requisite level of dispatchable resources.

5. Three-year strategic reserve – in view of the current risk in Victoria, AEMO believes its inability to procure reserves over a three-year duration is imposing unnecessary risks and costs on Victorian consumers. AEMO will therefore continue look to obtain the necessary and prudent flexibility that maintains reliability at the lowest cost.

6. Wholesale demand response – AEMO is reviewing the recent decision of the AEMC to support the introduction of wholesale demand response in the NEM. As envisioned by the AEMC, AEMO will look for was to accelerate participation by customers as a mechanism to support future reliability.

7. Market reform – the current forecast reliability risks, and the need for market-based investments, demonstrate the imperative to implement reforms in the NEM covering a number of areas. They include, for example, short-term forward markets, firming and security services markets, and markets to support investments at the right time and the right location, including nodal pricing and improved reliability mechanisms. AEMO will continue to work with the ESB and the other market bodies to help prioritise and progress market reforms that will improve how market participants can address consumer demands for reliable, secure, and affordable power.

8. Notice and mechanism of closure – the current three-year notice of closure rule for generators does not fully protect consumers from potentially significant high price and load shedding risks in the lead up to, and following, a major generator closure. As generators approach decommissioning, the risk of a major outage or unforeseen early exit due to economic consideration increases. Furthermore, the three-year closure period may not provide sufficient time to implement the most cost-effective replacement option, leading to higher cost outcomes for consumers. AEMO will work with governments, the ESB, and other market bodies to develop a proposal over the coming six months to refine the current rules to enhance long-term certainty of generator exit dates, while ensuring plant reliability in the lead up to the planned closure date.

9. Information transparency – AEMO is working with industry to increase the frequency and improve the content of information it publishes, to provide greater transparency and thereby improve decision-making. Improvements will include quarterly updates on generator commissioning and commitment in Generation Information Page updates4. AEMO will also investigate further generation, storage, demand side participation (DSP), and transmission measures in its upcoming 2019-20 ISP.

D3. Gas Statement of Opportunities (GSOO)

The 2019 Gas Statement of Opportunities (GSOO) contains AEMO's projections for demand, and information from gas producers about reserves and forecast production, to assess the projected supply-demand balance and potential supply gaps under a range of plausible scenarios for the outlook period to 2038, for the eastern and south-eastern Australian gas markets.

The 2019 GSOO highlights that the gas supply-demand balance remains tight, with gas production in southern Australia continuing to decline, and supplies from Queensland limited by pipeline capacity:

- Supply from existing and committed gas developments is forecast to provide adequate supply to meet gas demands until 2023. However, risks remain that any weather-driven variances in consumption or electricity market activity could increase gas demand, creating potential peak-day shortages as outlined in AEMO's 2019 Victorian Gas Planning Report[19].
- While new gas development is continuing in Victoria, reserve estimates have reduced, and producers are declaring more gas resources commercially unviable. Consequently, production from the southern gas fields is expected to decline over the 20-year outlook.
    - From 2021 to 2023, this decline in production will reduce Victoria's ability to export surplus gas supplies to South Australia and New South Wales, placing more reliance on Queensland supplies to meet gas demand in these states. It will also increase reliance on the Iona underground gas storage facility to meet winter demand in Victoria.
    - From 2024, major southbound pipeline infrastructure upgrades would be required to deliver more gas from northern to southern states (predominantly over the winter months when southern demand is highest). AEMO forecasts potential for supply gaps from 2024 onwards, unless additional southern reserves and resources, or alternative infrastructure, are developed.

- The 2019 GSOO confirms trends identified in the 2018 GSOO, including short-term reductions in demand for gas for gas-powered generation of electricity (GPG) and increases in demand for liquefied natural gas (LNG) exports. Longer-term, based on updated industry data and advice, this GSOO projects reduced demand and production in the LNG sector compared to the 2018 forecasts.
- Continued interest in LNG import terminals, particularly in Victoria, New South Wales, and South Australia, would be expected to help relieve pressure on meeting southern gas demand during peak periods and assist in reducing pipeline constraints, but may do little to ease gas pricing pressures.

[19] See AEMO's 2019 Victorian Gas Planning Report for more discussion on peak day gas concerns in Victoria. Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

D4. Draft 2020 Integrated System Plan

The ISP[20] is a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy through a complex range of plausible energy futures. Its scope is the whole NEM power system over the next 20 years.

With extensive stakeholder engagement, AEMO developed the Draft ISP using cost-benefit analysis and least-regret scenario modelling, covering five scenarios – Central, Fast Change, Slow Change, Step Change, and High DER.

The ISP will be updated at least every two years, with AEMO releasing the *2020 Draft ISP* in December 2019 and the *Final 2020 ISP* in mid-2020.

Key findings of the Draft ISP

The ISP modelling confirms that the least-cost and-regret transition of the NEM is from a *centralised* coal-fired generation system to a *highly diverse* portfolio dominated by Distributed Energy Resources (DER) and Variable Renewable Energy (VRE), supported by dispatchable resources and enhanced grid and service capabilities to ensure the power system can reliably meet demand at all times.

The ISP shows that by 2040:

- **Distributed energy generation capacity is expected to double or even triple.** AEMO modelling projects DER could provide 13% to 22% of total underlying annual NEM energy consumption[21] by 2040. With these higher levels of DER, dedicated management practices and protocols will be needed to maintain system security, backed by changes to rules, regulations and standards. New DER installations will increasingly need to have sufficient interoperability capabilities so they can be controlled when required for power system security. AEMO is currently investigating the maximum levels of uncontrollable energy that the system can accommodate while remaining secure.
- **Over 30 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. Allowing for the strong growth in DER, Australia will still need an additional 34 GW of new VRE in the Central scenario, above what is already committed, 30 GW for High DER, 37 GW for Fast Change or 47 GW for Step Change, much of it built in REZs. In the Slow Change scenario, only 4 GW would be needed by 2040.
- **5 to 21 GW of new dispatchable resources are needed in support.** To firm up the inherently variable distributed and large-scale renewable generation, we will need new

[20] AEMO. *Draft 2020 ISP*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[21] 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.

flexible, dispatchable resources: utility-scale pumped hydro or battery storage, distributed batteries participating as VPP, and demand side participation (DSP). New flexible gas generators could also play a greater role if gas prices materially reduce.

- **Power system services are critical to support these three sets of energy resources.** Innovative power system services will be needed that span voltage control, system strength, frequency management, power system inertia and dispatchability.
- **The transmission grid itself needs targeted augmentation to balance resources and unlock REZs.** While over 30 GW of new VRE may be required by 2040, the existing network only has an estimated connection capacity for 13 GW in areas with favourable renewable resources. 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.

The Optimal Development Path

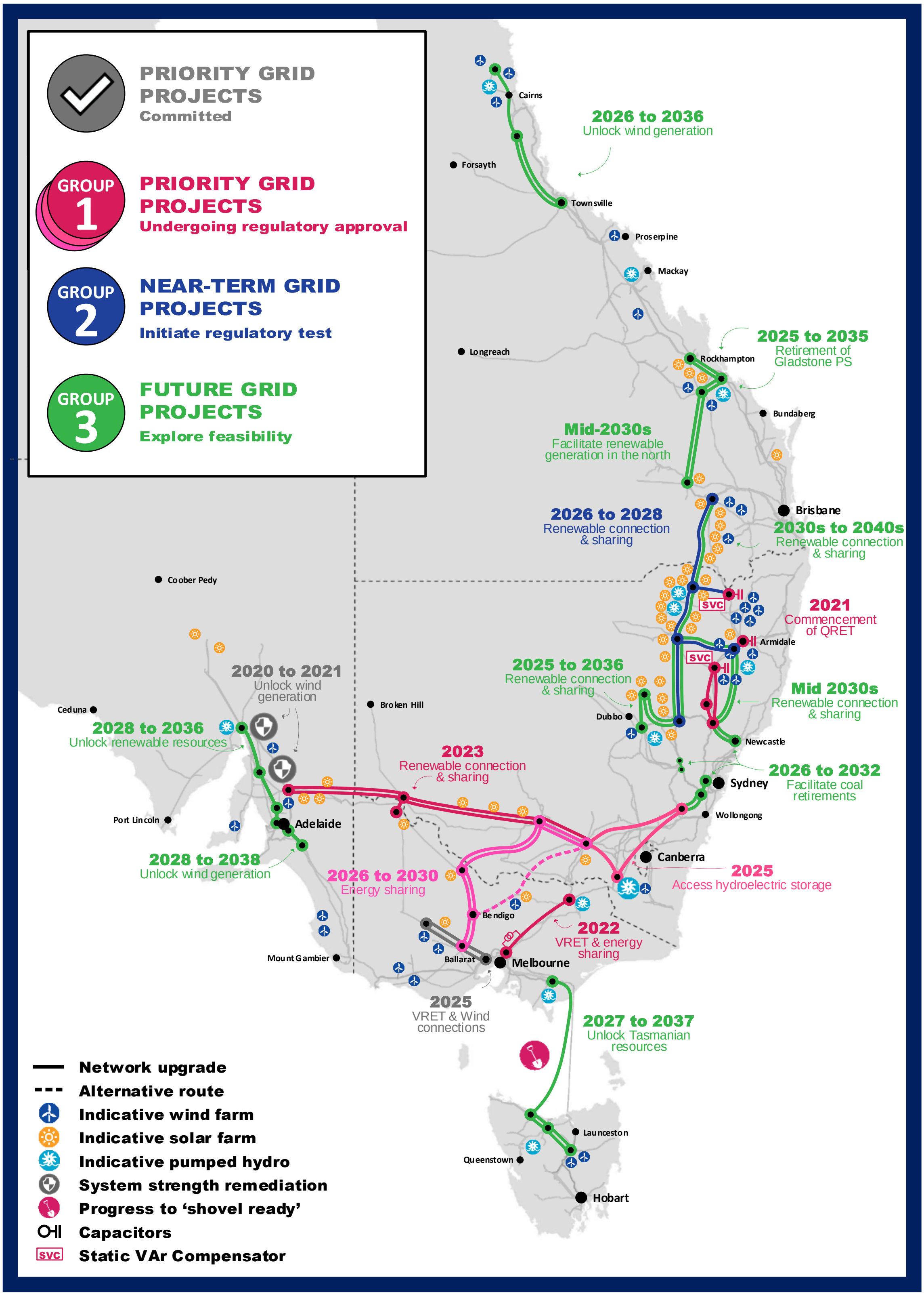
The ISP identifies over 15 projects to augment the transmission grid, which have been selected from a large range of possible options. These projects fall into three time-related groupings to achieve power system needs through a complex, energy sector transition.

- **Group 1 – Priority grid projects** are critical to address cost, security and reliability issues. They are to commence immediately after the publication of the final 2020 ISP, if not already underway. They fall into three categories:

  - Already committed projects include South Australia system strength remediation and Western Victoria Transmission Network Project.
  - Actionable ISP projects including minor Queensland to NSW (QNI) and Victoria to NSW (VNI) interconnector upgrades, Project EnergyConnect (a new interconnector between SA and NSW), HumeLink (reinforcing southern NSW) and VNI West (a new high capacity interconnector between Victoria and NSW).
  - A recommended project to progress with the design and approval process for Marinus Link (a second, and potentially third, HVDC cable connecting Victoria and Tasmania) to reach a shovel-ready stage.

- **Group 2 – Near-term grid projects** are important projects that require actions in the near future and at the latest prior to the publication of the 2022 ISP to reduce costs, enhance system resilience and optionality. These projects include the QNI medium interconnector upgrade, which should be delivered by 2028-29 with an option of accelerating delivery to 2026-27 should the Step Change scenario emerge.
- **Group 3 – Future grid augmentation projects** provide valuable future options for Australia's energy system, but with time at least until the 2022 ISP before final decisions on actionability and/or investment must be made. This allows time to further investigate and refine these options. These projects include Marinus Link, Queensland grid reinforcements, NSW grid reinforcements and network required to support REZ expansions.

FIGURE 1 THE DEVELOPMENT PATHS FOR THE NEM IN THE DRAFT 2020 ISP



ISP development opportunities in Renewable Energy Zones

Development of additional VRE in REZs across the NEM will occur in three overlapping phases of development.

Phase 1 To help meet regional RETs (such as VRET and QRET) and other policy initiatives (such as the NSW Electricity Strategy) until those schemes are complete and/or where there is good access to existing network capacity with good system strength, good resource potential, and alignment with community interests.

Phase 2: To replace energy provided by retiring coal-fired generators – announced to occur from the late 2020s and/or where additional development is supported by the recommended transmission projects in Group 1 and 2 of the optimal development path or where there is good access to existing network capacity with good system strength, good resource potential, and alignment with community interests.

Phase 3: To accompany recommended group 3 transmission projects that are being developed specifically to support them.

Next steps and Consultation

From mid-2020, the development and implementation of the ISP will be a regulated requirement under the National Electricity Rules. To achieve a smooth transition, AEMO has aligned its analysis and work with the current draft of the ISP Rules, being developed concurrently by the ESB. This alignment includes the completed Inputs, Assumptions and Scenarios work, the content of the draft Plan, consultation on the Draft ISP 2020 and the call for non-network options. Following the release of the Draft 2020 ISP, AEMO's consultation on the ISP includes:

1. Public forums on the Draft ISP on 3-5 February 2020.
2. Written submissions to the Draft ISP before 21 February 2020.
3. AEMO may hold further information sessions in February and March 2020.
4. The deadline for submissions on both the QNI Medium call for non-network options and the VNI West Project Specification Consultation Report (PSCR) is 13 March 2020.

In parallel, AEMO has commenced consultation on inputs and assumptions for other forecasting and planning work in 2020. Submissions are called for by 7 February 2020.

2019 AER Major Reports

E1. State of the energy market

Brief summary of the report

The *State of the energy market* report aims to give readers a working understanding of how the markets operate so they can make their own assessment of the issues. The report aims for non-technical language to reach as wide an audience as possible.

Stakeholders value the report as a ready source of unbiased and up-to-date information about what's happening in Australia's wholesale electricity and gas markets, the transmission and distribution networks and the retail energy sector. It draws on a range of sources, including the AER's market performance reports, monitoring and intelligence, regulatory reviews of energy networks and external resources. The report consolidates this material to highlight trends and key issues across the industry.

The 11th *State of the energy market* report was published in December 2018. It covered issues including why retail energy bills are higher than in the past, how renewable generation is changing the market, how Australia's gas industry is responding to the needs of foreign and domestic customers, how energy networks can be managed to meet changing customer expectations and the impact of government intervention in the market.

State of the energy market is evolving as the market itself evolves. In 2019 the AER began publishing the report's most frequently requested data sets online. Updated data was published in November 2019.

The 12th edition of *State of the energy market* is scheduled to be published by May 2020.

E2. Annual retail market report 2018-19 and quarterlies for 2018-19

Brief summary of the report

The AER published the *Annual retail market report 2018-19* on 27 November 2019. Prior to this the AER published three quarterly reports for this financial year (Quarter 1 July to September 2018, Quarter 2 October to December 2018, Quarter 3 January to March 2019).

The following findings were made in the *Annual retail market report 2018-19*.

Market structure

- Tier 1 retailers continue to hold the greatest market share in NSW, South Australia and south-east Queensland.
- Ergon, ActewAGL and Aurora continue to hold the greatest market share in regional Queensland, the ACT and Tasmania, respectively.
- Tier 2 retailers increased market share in all market segments.
- The proportion of customers on market contracts increased in the residential electricity and gas and small business electricity market segments.
- The proportion of residential customers on market contracts increased in all jurisdictions except Tasmania.
- Six new retailers were authorised in the 2018–19 year and various existing retailers entered new market segments.

Market activity

- Switching between retailers varied between jurisdictions.
- During 2018, most jurisdictions had peaks in the rates of switching between retailers and have since seen a downward trend in switching across electricity and gas.
- Victorian customers continued to have the highest rates of switching between retailers.
- ACT customers were the least likely to switch between retailers but the most likely to switch from standing to market contracts.

Retailer customer service

- In 2018-19, while some retailers performed well against call responsiveness indicators, others still have room for improvement (particularly the 'major retailers').
- 207 408 customers (2.9 % of customers) raised complaints, down from last year.
- Billing issues remained the top cause of complaints.
- 35 378 customers contacted an ombudsman when they were unable to resolve their complaint with their retailer.

Payment difficulties and hardship

Concessions

- The proportion of customers receiving concessions decreased slightly for both electricity and gas customers.

Energy debt – non-hardship

- The proportion of residential and small business customers in debt decreased compared to last year.
- The level of residential debt has decreased across most jurisdictions, except for Tasmania, and small business debt remains steady.

Credit collection

- This new indicator revealed that customers are being referred for collection activity for debt that is often less than $500.
- About half of the customers referred for collection activity received a negative credit rating as a result of their unpaid energy debt.

Payment plans

- The proportion of customers on payment plans increased for residential electricity customers and decreased for residential gas customers.
- The proportion of both electricity and gas payment plans cancelled due to customers' non-compliance remained high in 2018-19, although it decreased from last year.

Hardship programs

- The proportion of residential electricity customers on hardship programs increased in all jurisdictions except Queensland. For gas, the proportion remained steady, except that it decreased in South Australia and increased in the ACT.
- The average debt of electricity hardship customers was significantly higher this year. The average debt of gas hardship customers was steady across jurisdictions, except for in the ACT where it increased substantially.
- Well over a third of customers on hardship payment plans are not meeting their ongoing energy usage costs.

Disconnections

- The proportion of residential electricity customers disconnected per year reduced marginally over the past year, after stabilising at a high level in recent years. In addition, there was an increase in the proportion of small business electricity disconnections over the past year.
- Overall, the average proportion of residential and small business gas customer disconnections decreased this year.
- Queensland and South Australia reported the highest proportion of electricity and gas customers disconnected.

Compliance and enforcement

- AER enforcement action in 2018–19 resulted in retailers and distributors paying $320 000 in penalties, in response to 16 infringement notices, for allegedly failing to meet their obligations under the Retail Law and Rules. Of those, 11 alleged breaches related to supply disruptions to customers on life support equipment, three to failure to provide accurate and timely performance data under the AER Performance Reporting Procedures and Guidelines, and two to failures to obtain a customer's explicit informed consent to a market retail contract.

- In November 2019, the AER instituted proceedings in the Federal Court against four subsidiaries of AGL Energy for alleged failures to submit information and data about their performance and activities as required by the AER Performance Reporting Procedures and Guidelines.
- In addition to enforcement action, the AER's compliance activities in 2018–19 included:
- Oversight of the implementation of new rules, including strengthened protections for life support customers and new meter installation timeframes.
- Publication of the AER's new Customer Hardship Policy Guideline. In accordance with the new Guideline, 50 new and improved customer hardship policies were submitted for approval in June.
- Completion of five compliance audits under the Retail Law and Rules, and initiation of a further three. Audit targets included retailers' customer hardship policies, the requirement to obtain and record customers' explicit informed consent to market retail contracts and transfers between retailers and distributor obligations to register and protect life support customers.
- Revisions to the AER Compliance Procedures and Guidelines to incorporate reporting requirements for new rules introduced by the Australian Energy Market Commission and to update the way AER conducts, or requires businesses to conduct, compliance audits under the Retail Law.

E3. Affordability in retail energy markets

Brief summary of the report

The AER published its first *Affordability in retail energy markets* report in September 2019. The main purpose of this report is to look at how energy affordability changed over the period 2017 to 2019.

The price of electricity and gas has gone up over the last decade. At the same time as rising energy prices, income growth has been flat in many households.

The *Affordability in retail energy markets* report provides a high-level analysis of energy affordability in New South Wales, Queensland, South Australia, the Australian Capital Territory, Victoria and Tasmania with a focus on the affordability of energy for low income households. It also provides an early analysis of the effect of the Default Market Offer arrangements introduced by the Australian Government in July 2019. These regulations, which are administered by the AER, place a cap on what retailers can charge customers on electricity standing offers in New South Wales, south-east Queensland and South Australia.

The data contained in the report indicates some modest improvements in energy affordability over the past year, although energy is still difficult to afford by historical standards.

Paying energy bills is a major concern for many Australian households, especially those on low incomes. This report shows that low income households on a typical market offer spent 4.8 to 7.6 % of their disposable income on electricity and 2.6 to 5.5 % on gas.

For customers on standing offers the cost of their energy is typically even higher. For example, for a low income household in South Australia, the difference between annual electricity bills on the median market offer relative to the median standing offer is $532. This translates into a difference between spending 9.9 % or 7.6 % of their disposable income on electricity.

Table 9 below shows annual median bills and percentage of household income for average income and low income households across all jurisdictions* in 2018-19.

TABLE 1: ANNUAL MEDIAN BILLS 2019

	Electricity			Gas		
Jurisdiction	Median Market Offer	% disposable income – average income customers	% disposable income – low income customers	Median Market Offer	% disposable income – average income customers	% disposable income – low income customers
NSW	$1 885	3.2	6.9	$865	1.5	3.3
QLD	$1 669	3.2	5.8	$664	1.3	2.6
SA	$2 022	3.9	7.6	$924	1.8	2.8
TAS						
ACT	$1 710	2.6	4.8	$1 547	2.3	4.2

VIC	$1 502	2.7	5.5	$1 521	2.8	5.5

Table 10 below shows bill price movements across all jurisdictions in 2018-19 compared to 2017-18.

TABLE 2: PERCENTAGE CHANGE IN ANNUAL BILL MOVEMENTS FROM 2018 TO 2019

	Electricity		Gas	
Jurisdiction	Median Market Offer	Median Standing Offer	Median Market Offer	Median Standing Offer
NSW	-7.2 %	-0.5 %	-1.5 %	2.5 %
QLD	-9.3 %	-3.1 %	-1.8 %	1.1 %
SA	-8.0 %	-4.1 %	0.0 %	0.1 %
TAS		1.2 %		
ACT	-5.3 %	3.3 %	-2.7 %	3.7 %
VIC	-0.5 %	-3.1 %	4.3 %	6.7 %

*Please note that the AER does not regulate gas in Tasmania, and due to the small number of electricity market offers in Tasmania skewing results, electricity market offers sections are left out. Tasmania has around 6 % of residential electricity customers on market contracts.

The AER encourages households, where possible, to seek out the best possible deal they can for their circumstances. EnergyMadeEasy, AER's independent and free of charge price comparison website, provides the information you need to compare the various offers in your area so you can see if you would be better off under a different deal. Choosing the right deal can make a big difference to your energy bills.

The AER expects to release the next affordability report in the second half of 2020.

E4. AER $5,000 reports

Brief summary of the reports

Under the Electricity Rules, the AER is required to publish a report whenever the spot price for electricity exceeds $5 000/MWh. It also has an obligation to publish a report when the ancillary service price exceeds $5 000/MW for a sustained period. These reports identify and describe the factors contributing to the high prices, including rebidding, network issues or changes to demand and generator availability.

The AER released four of these reports in 2019 – three reports into spot prices over $5 000/MWh in Victoria and South Australia and one report into ancillary service prices over $5 000/MW in Queensland.

Reports into spot prices over $5 000/MWh in Victoria and South Australia on Main drivers of the price spikes on 24 and 25 January and 1 March 2019 (published 26 March and 1 May 2019)

Over three days in Q1 2019, there were 16 trading intervals (equivalent to 8 hours) in Victoria and 15 in South Australia when spot prices exceeded the $5 000 per MWh reporting threshold. The spot prices were high due to:

- High demand driven by high temperatures. In South Australia, temperatures reached a record of 48°C in Adelaide on 24 January and 40°C on 1 March, while in Victoria maximum temperatures reached at least 38°C on each of the three days of high prices.
- Low supply of wind generation in Victoria and South Australia. On each of the high price days, a maximum of around 600 MW of wind generation was available, compared to installed dispatchable capacity of almost 2 600 MW across both regions.
- Thermal plant outages in Victoria due to technical plant failures. Around 900 MW of thermal capacity on 24 January and 1 240 MW on 25 January was unavailable.
    - A generator at EnergyAustralia's Yallourn power station (355 MW) had a seven-day planned maintenance outage, scheduled from 18 January. However, following high forecast demand, the outage was delayed by one day, and the plant went offline the day after. Due to technical plant issues, the unit was unable to return to service within the seven day schedule, and remained offline for more than two weeks.
    - At the same time, boiler tube leaks that led to plant failures caused an additional 530 MW of outages on 24 January and 885 MW on 25 January. AGL's Loy Yang A unit 3 (530 MW) came offline from 22 January, while a second Yallourn unit (355 MW) was limited to 300 MW on 24 January but had to go offline for maintenance on 25 January.

For all outages, the Australian Energy Market Operator (AEMO) was notified as soon as the issues were identified, and forecasts were updated accordingly.

Report into ancillary services prices over $5 000/MW in Queensland on 25 August 2018 (published 19 June 2019)

On Saturday 25 August 2018, the price for all eight frequency control ancillary services (FCAS) exceeded $5 000/MW in Queensland for most of the dispatch intervals between 1.25 pm and 2.45 pm.

A single lightning strike on a transmission tower structure supporting the two circuits of the Queensland to New South Wales interconnector (QNI) caused QNI to “trip” at just after 1 pm, islanding the Queensland region from the rest of the National Energy Market (NEM). As a result, frequency in the Queensland region increased and fell in the rest of the NEM.

Consistent with standard practice, AEMO required Queensland to source all FCAS from within the region. To manage the security of the system in Queensland, AEMO invoked constraints to limit the output of generators in Queensland to 350 MW. All available local ancillary services in Queensland were used in an effort to maintain frequency in the region, some of which were priced very high. This contributed to the high prices. In addition, at times the level of available local FCAS was not sufficient to meet the required amount set by AEMO. The trade-off between the competing demands for energy and FCAS led to FCAS prices exceeding $14 000/MW.

Strategic rebidding by participants did not contribute to the price exceeding $5 000/MW.

The event in Queensland had a cascading effect in other regions. The reduction in frequency across the NEM caused an increase in flows of electricity from Tasmania to Victoria across the Basslink interconnector, causing 81 MW of load to be shed in Tasmania (under the automatic under-frequency load shedding scheme). The reduction in frequency also activated the emergency control scheme on the Vic-SA (Heywood) interconnector, causing it to trip. In South Australia all services, with the exception of 60 second raise, experienced one dispatch interval above $5 000/MW between 1.25 pm and 1.45 pm.

The reduction in frequency in the “islanded” New South Wales/Victoria region triggered under-frequency load shedding – a total of 997 MW of supply was interrupted: 904 MW of smelter load across the two regions (622 MW at Tomago in New South Wales, and 282 MW at Alcoa in Victoria) and 93 MW of consumer load in New South Wales. For all outages, AEMO was notified as soon as the issues were identified, and forecasts were updated accordingly.

E5. AER wholesale electricity market performance report

Brief summary of the report

Under the National Electricity Law, the AER is required to monitor and report on the performance of the NEM. This includes analysing and identifying whether there is effective competition in the market, and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market. The AER must report on the performance of the market at least every two years and may also advise COAG Energy Council on market performance and identify whether legislative or regulatory reform is required.

The AER's wholesale electricity market performance report of December 2018 is the first report released under this role covering all NEM regions.

The report found that the wholesale electricity market is undergoing a significant transformation, with market dynamics changing as it transitions to a lower emissions generation mix. In recent years, average wholesale electricity prices have risen significantly, as a result of the exit of low cost generation and increasing fuel costs.

The report noted that there are elements of the market which make it vulnerable to the exercise of market power. Large vertically integrated participants control significant generation capacity and the output of a few large participants is required to meet demand in most regions a significant proportion of the time. Despite this vulnerability to the exercise of market power, the report did not identify short-term behaviour as contributing to recent price rises.

The report also highlighted that while the NEM continues to meet the reliability standard, supply and demand conditions have tightened, and prices have risen to such a level that a signal for some lower cost technologies is emerging. This is consistent with the considerable investment in new wind and solar generation on the horizon. However, market participants have identified a range of potential barriers to entry, including policy instability and unpredictability, interventions in the market, and difficulties in obtaining finance.

The next AER wholesale electricity market performance report is due in December 2020. The AER has commenced the process for developing this report with the release in November 2019 of the *Wholesale electricity market performance – 2020 Focus* identifying the areas for analysis in the coming report.

While this performance report is required every two years, the AER undertakes other reporting into the performance of the wholesale market. Notably, the AER now produces a quarterly report into the performance of wholesale energy markets. Not only does this support the AER in monitoring and reporting on a more ongoing basis, but his works also informs the longer term performance reporting.

E6. Annual benchmarking report for distribution and transmission networks

Brief summary of the report

The AER publishes annual benchmarking reports that examines the productivity of electricity distribution and transmission network service providers in the national electricity market.

The AER is required to publish these reports under the National Electricity Rules (NER). The AEMC added these requirements to the NER in 2012 to:

- reduce inefficient capital and operating network expenditures so that electricity consumers would not pay more than necessary for reliable energy supplies, and
- to provide consumers with useful information about the relative performance of their electricity network service provider to help them participate in regulatory determinations and other interactions with their service provider.

The 2019 benchmarking report examines network productivity over 2006 to 2018, with a particular focus on the changes in productivity over 2017 to 2018.

The distribution and transmission benchmarking reports show that:

- the productivity of the electricity distribution networks has improved by 1 % in 2018. This is the third consecutive year of growth and this rate of productivity has outpaced the wider economy.
- the productivity of electricity transmission networks productivity improved by 2.2 % over 2018.

Improving the productivity of distribution and transmission networks means customers should benefit through downward pressure on network charges and customer bills.

The next benchmarking report will be published by 30 November 2020.

E7. Black system event compliance report

Brief summary of the report

In 2017 and 2018 the AER conducted a detailed investigation the actions of participants in the state-wide blackout in South Australia on 28 September 2016. This significant event was the first of its kind in the history of the NEM, and the scope and complexity of the AER's subsequent investigation have been unprecedented.

Given the magnitude of these events, the AER separated its investigation into four separate parts:

- The Pre-event period, which focussed on AEMO and ElectraNet's actions in the lead up to the storm event, in particular whether they fulfilled their obligations under the Electricity Rules in relation to power system security;
- The Event, in which we focussed on the compliance of generators with their performance standards during multiple power system faults experienced in the period immediately prior to the system going black in South Australia;
- System Restoration, in which we examined the actions of certain participants in relation to the provision and use of System Restart Ancillary Services to restore the network following the black system conditions of 28 September 2016; and
- Market Suspension, in which we assessed compliance with how participants operated during the 13 day period in which the spot market in South Australia was suspended, including how AEMO managed power system security.

In December 2018, the AER released the findings of their investigation into the other three components: the pre-event period, the restoration of the energy supply system, and the suspension of the market. The Event component remained under investigation until August 2019 when the AER instituted proceedings against four wind farm generators.

Overall, the investigation into the pre-event period, the restoration of the energy supply system, and the suspension of the market found a high level of compliance by market participants with their obligations. However there were instances in which obligations were not complied with. In particular, the AER found that AEMO did not comply with five clauses of the Electricity Rules in relation to action during the pre-event and market suspension periods. The AER considers that these breaches did not contribute to the state going black, and that all core obligations were met.

Importantly, the report outlines a number of recommendations to improve the overall effectiveness of the regulatory framework. These actions include:

- implementing more rigorous weather monitoring processes
- standardising notifications for market participants during abnormal weather conditions
- more broadly reviewing the criteria under which weather events are classified
- improving AEMO operator training
- clarifying roles and responsibilities of the market operator and network providers regarding system restoration.

A number of these recommendations, including those related to AEMO practices, systems and processes, have already been implemented, and others are in process. The AER's report has also been a key input into the policy review of the regulatory framework being conducted by the AEMC.