Image courtesy of Powering Australian Renewables.

1

The electricity market in transition

Australia's electricity markets are undergoing a profound transformation from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, grid scale batteries and demand response.

The mix of electricity generation is changing, both at grid scale and at the individual customer level. Ageing coal fired and gas powered generation has left the market and been replaced by large scale wind and solar capacity.

Additionally, some energy customers are adopting their own 'behind the meter' energy solutions – namely, distributed energy resources (DER) that include rooftop solar photovoltaic (PV) installations, small batteries, electric vehicles (EV) and demand response. Where power once moved in one direction, from large generators through transmission and distribution lines to end customers, significant 2-way flows of power now occur. At times electricity demand from the grid is close to zero in some regions.

A web of interrelated factors has driven (and continues to drive) this transition. Community concerns about the impact of fossil fuel generation on carbon emissions are a major catalyst, driving policy initiatives by governments and behavioural change by energy customers and businesses. Government incentives for lower emissions generation encouraged early investment in wind, solar farms and small scale solar PV systems. A trend of rising energy prices over the past decade gave further impetus to this transition by driving customers to use energy more efficiently and to generate their own power. These developments helped establish Australia's solar PV and wind industries.

While government policies on climate change helped drive the surge in renewable energy, the declining costs of renewable plant (both commercial and small scale) have made them the most economic options for new build generation. This cost advantage over thermal plant is forecast to widen over the next 2 decades as economies of scale and technology improvement further reduce costs, particularly for solar plant and batteries.

The weather-dependent nature of renewable generators makes their output variable and sometimes unpredictable. The market needs 'firming' capacity (such as fast-start generation, demand response and battery storage) to fill supply gaps when a lack of wind or sunshine curtails renewable plant. Sophisticated demand and supply forecasting is also required to ensure sufficient firming capacity is available when needed.

Coal and gas powered generators also provide the market with inertia and system strength which help stabilise the grid.[1] Reduced output from these plants as renewables output grows makes the transmission network more susceptible to erratic frequency shifts and voltage instability.[2] And, with new plants locating in sunny or windy areas at the edges of the grid where network capacity is limited, additional measures are needed for efficient supply to customers. Two-way power flows are also creating similar pressure points in local distribution networks.

Finding the best ways to keep the power system reliable and secure as the generation mix evolves continues to be a pivotal challenge. Improved data and technology services provide some solutions. New renewables plants, for example, are now required to provide some system security services traditionally provided by fossil fuel plants. During the transition, however, more frequent market interventions have been needed to maintain a reliable and secure power system.

Strategic planning and policy and regulatory reforms are being implemented to guide the transition to optimise benefits for energy customers. A new fit-for-purpose electricity market framework – NEM 2025 – is being developed to ensure the market signals opportunities for new generation investment and for services needed for system security, and to effectively integrate DER.

A well-managed transition will deliver significant benefits. Renewable energy is a relatively cheap fuel source and, if integrated efficiently into the power system, can deliver low cost sustainable energy. For customers, the uptake of solar PV and battery systems (when supported by appropriate control systems) can help them save on power bills and manage energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

1 Box 1.4 defines these terms.

2 Box 1.4 defines these terms.

1.1 Drivers of change

Community concerns about the impact of fossil fuel generation on carbon emissions, along with technology changes and an ageing coal fired generation fleet, are among factors that have driven and continue to drive Australia's energy market transition.

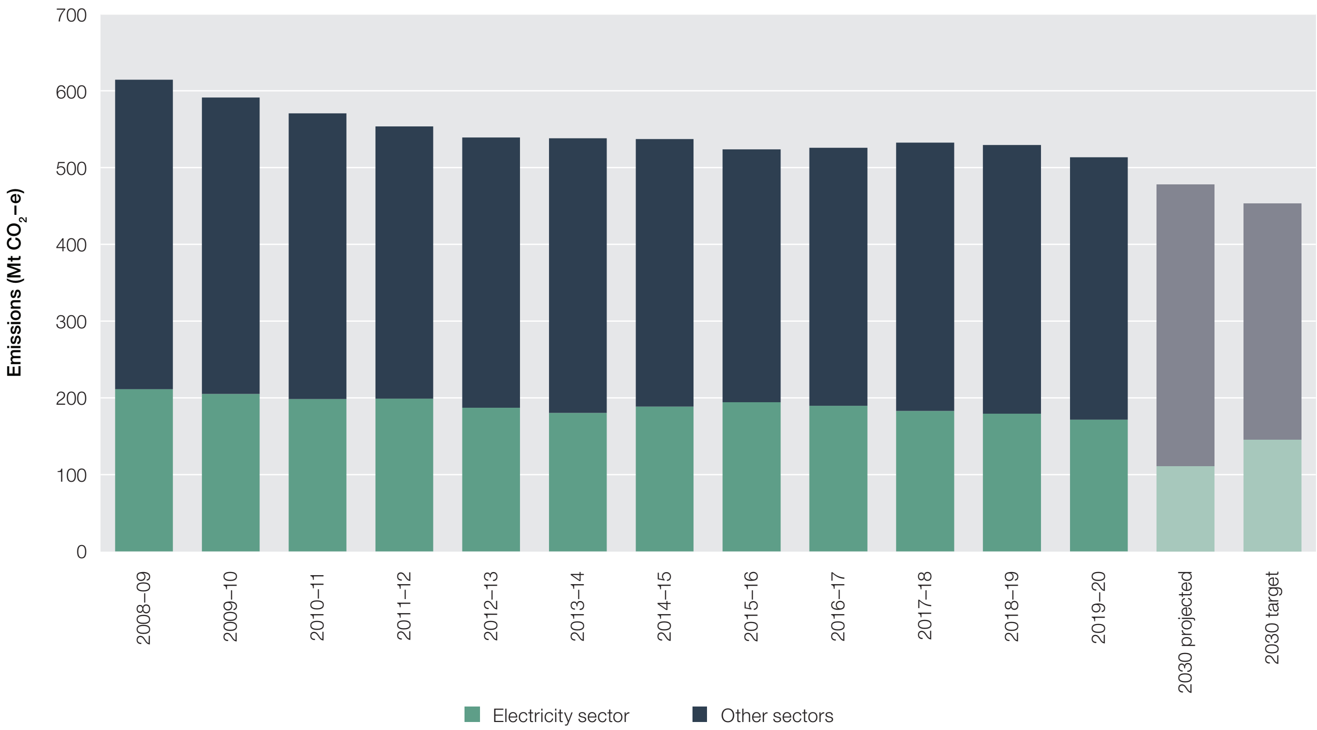
1.1.1 Action on climate change

Environmental concerns were a major catalyst for the transition underway in the electricity sector. Australia has international commitments under the Paris Agreement (2016) to reduce its carbon emissions by 26-28% below 2005 levels by 2030. The agreement set no specific target for the electricity sector.

Australia's carbon emissions have trended down over the past decade (figure 1.1). The electricity sector has become increasingly important in driving this trend, with emissions reductions of almost 12% over the past 5 years. Emissions across other sectors rose by 4% over this period.

Despite this shift, the electricity sector remains the largest contributor to national carbon emissions, accounting for 33% of Australia's total emissions in 2019–20. Victoria's brown coal plants are the most emission-intensive power stations in the NEM, followed by black coal plants in Queensland and New South Wales (NSW) and gas powered generation. Wind, hydroelectric and solar PV power stations generate negligible emissions.[3]

Figure 1.1 Australia's carbon emissions



Mt CO_2-e: million metric tonnes of carbon dioxide equivalent.

Note: Electricity sector emissions exclude stationary energy, transport and fugitive emissions.

The 2030 target is based on Australia's Paris commitment of a 26% reduction on 2005 emissions levels and assumes a proportional contribution by the electricity sector.

Projected 2030 emissions are as forecast by the Department of Industry, Science, Energy and Resources in December 2020 in the absence of policy intervention.

Source: Department of Industry, Science, Energy and Resources, *Quarterly update of Australia's national greenhouse gas inventory*, June 2020; Department of the Environment and Energy, *Australia's emissions projections*, December 2020.

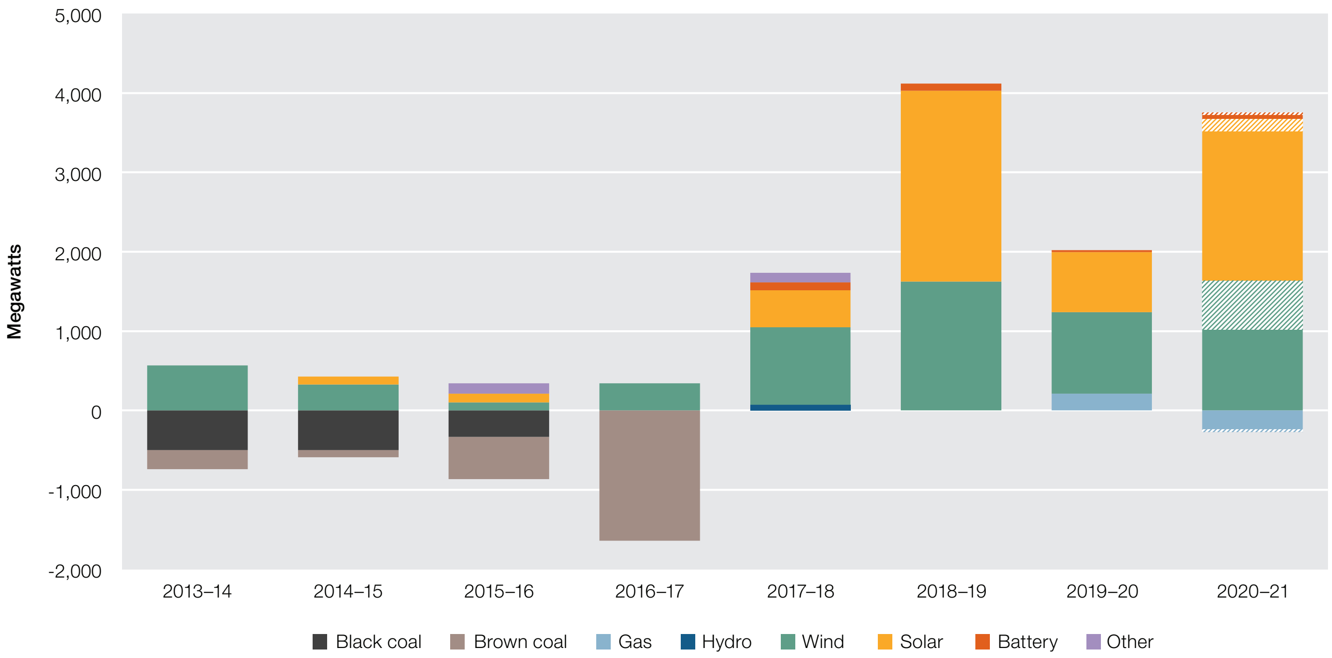
3 Department of the Environment and Energy, *National greenhouse accounts factors,* October 2020.

Australian Government policies to reduce carbon emissions focus on financial incentives for private investment in lower emission generation (box 1.1). The schemes have encouraged significant investment in wind and solar farms and small scale solar PV systems.

Alongside national policies, several state and territory governments set renewable energy targets that are more ambitious than the national scheme. Programs encouraging new renewable entry typically support these targets. More generally, several jurisdictions have launched comprehensive energy plans that include climate change settings and new initiatives to meet targets (section 1.7).

Energy businesses have also responded to concerns about climate change through new strategies for generation investment. No energy business has invested in new coal fired generation in Australia since 2012 (figure 1.2). Commercial businesses are also self-generating more of their energy requirements (mostly through solar PV systems).

Figure 1.2 Entry and exit of generation capacity in the National Electricity Market



Note: Capacity includes scheduled and semi-scheduled generation but not non-scheduled or rooftop PV capacity. 2020–21 data are at 31 March 2021. Investment and closures expected between 1 April and 30 June 2021 are shown as shaded components.

Source: AER; AEMO (data).

Box 1.1 Emission reduction policies and the electricity industry

Australian government policies aimed at reducing carbon emissions from electricity generation are outlined below.

Renewable energy targets

The Australian Government operates a national Renewable Energy Target (RET) scheme that incentivises large (such as wind and solar farms) and small (such as rooftop solar photovoltaic (PV)) scale energy supply. It requires energy retailers to buy renewable energy certificates for electricity generated by accredited power stations or from the installation of eligible solar hot water or small generation units. The certificates allow renewable generators to earn revenue above what they earn from selling electricity in the wholesale market.

The RET scheme set a 2020 target for energy from large scale renewable projects at 33,000 gigawatt hours (GWh). Sufficient renewable generation was committed by September 2019 to meet this target.[4] The Australian Government's policy is to not increase the target beyond the 2020 requirement and to not extend or replace the target after it expires in 2030.[5] As renewable generation capacity in the market has expanded beyond that needed to meet the 33,000 GWh target, renewable energy certificate values have fallen.

Some state and territory governments set renewable energy targets that are more ambitious than the national scheme:

- The Victorian Government set a legislated target of 25% of the state's electricity to be sourced from renewable resources by 2020, 40% by 2025 and 50% by 2030. Victoria met its 25% target in 2020.
- The Australian Capital Territory (ACT) Government achieved its legislated target of 100% of Canberra's electricity being met by renewable generation by 2020. It has a broader target for the ACT to be carbon neutral by 2045.
- The South Australian Government is targeting 100% net renewable energy generation by 2030. It has also announced plans to achieve renewable energy of more than 500% of current local grid demand by 2050.
- The Queensland Government has an unlegislated target of 50% renewable generation by 2030.
- New South Wales (NSW) does not have a renewable energy target but aims to achieve net zero emissions statewide by 2050.

To support these targets, state and territory governments run programs encouraging investment in renewables:

- The Queensland, Victorian, and ACT governments have offered 'contracts for difference' to new renewable generation investments and batteries, awarded through reverse auctions.[6]
- The Queensland Government established CleanCo, a new generation company that directly invests in renewable and gas firming capacity.
- Queensland, NSW and Victoria are developing renewable energy zones to reduce the risks and costs of renewables investment. The NSW Government's Electricity Infrastructure Roadmap proposes underwriting 12 GW of renewable energy across 5 renewable energy zones.
- The Queensland, Victorian, South Australian and ACT governments operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems.

More generally, state and territory governments operate energy efficiency schemes that encourage households and small business customers to reduce their electricity demand.

4 Clean Energy Regulator, '2020 Large-scale Renewable Energy Target capacity achieved' [media release], CER, 4 September 2019.

5 Commonwealth, Parliamentary Debates, House of Representatives, 18 September 2018, 9325 (The Hon Angus Taylor MP, Minister for Energy).

6 Contracts for difference provide a hedge for the holder by locking in future wholesale electricity prices (section 2.7).

Australian Renewable Energy Agency and the Clean Energy Finance Corporation

The Australian Government funds 2 key renewable energy investment agencies – the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC).

ARENA was established in 2012 to fund the research, development and commercialisation of renewable technologies. The agency funds innovative projects that would otherwise struggle to attract sufficient funding or be potentially lost to overseas markets.

From its inception to February 2021, ARENA invested $1.7 billion in over 550 projects, with a combined value of $6.9 billion. The projects include solar PV, hybrid, solar thermal, bioenergy, ocean, hydrogen, geothermal, grid integration, battery and pumped hydro storage projects. ARENA's focus since 2019 has been on projects that integrate renewables into the electricity system, accelerate the development of hydrogen energy supply and support industry efforts to reduce emissions.[7]

The CEFC was launched in 2012 as a government-owned green bank to promote investment in clean energy. The fund provides debt and equity financing (rather than grants) for projects that will deliver a positive return. CEFC finance of around $8 billion has supported around 200 large scale projects and 18,000 smaller scale projects, including commercial solar and wind, and storage and energy efficiency projects.[8]

Additionally, ARENA and the CEFC jointly manage the Clean Energy Innovation Fund, which provides debt and equity for clean energy projects at early stages of development that require growth capital.

In September 2020 the Australian Government proposed an amendment to the rules governing ARENA and CEFC to widen the scope of low emissions technologies they may support. It committed to additional funding of $1.9 billion for the agencies to invest in technologies including carbon capture and storage, hydrogen, soil carbon and green steel.

The government also introduced legislation for the CEFC to administer a $1 billion Grid Reliability Fund to fund the Underwriting New Generation Investment (UNGI) program (section 1.7.1). The fund aims to encourage private investment in generation, energy storage and transmission projects to balance the grid and deliver affordable power. The legislation defines gas as a low emissions technology to enable the CEFC to support gas generation projects under the fund. The legislation was before parliament in early 2021.[9]

Climate Solutions Fund

Under the Australian Government's Climate Solutions Fund (called the Emissions Reduction Fund until February 2019), the government pays for emission abatement through 'reverse' auctions run by the Clean Energy Regulator. Twelve auctions were held to April 2021, with spending commitments of $2.5 billion to abate 205 million tonnes of carbon emissions (an average price of $12.32 per tonne of abatement).[10]

In total, around 66 million tonnes of carbon abatement had been delivered by April 2021. Many funded projects involved growing native forests or plantations. The electricity sector made less than 2% of the carbon abatements under the scheme. Participating electricity projects mostly capture and combust waste methane gas from coal mines for electricity generation.[11]

Following a review, in May 2020 the government announced an expansion of the scheme, including the scoping of carbon capture and storage technology.[12] The model for participants to offer abatement under these categories is scheduled for completion by September 2021.

7 ARENA, *ARENA at a glance*, ARENA website, accessed 16 February 2021.

8 CEFC, *2019–20 investment update*, 2020.

9 Parliament of Australia, Clean Energy Finance Corporation Amendment (Grid Reliability Fund) Bill 2020, Australian Parliament House website, accessed 23 March 2021.

10 Auction results published by the Clean Energy Regulator, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results.

11 Projects do not necessarily connect to the NEM.

12 The Hon Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Building on the success of the Emissions Reduction Fund' [media release], 19 May 2020.

1.1.2 Technology and cost changes

While government policies on climate change helped drive the surge in renewable energy, the declining costs of renewable plant (both commercial and small scale) accelerated the shift. Improvements in plant technologies and the scale benefits of an expanding market are driving these cost improvements.

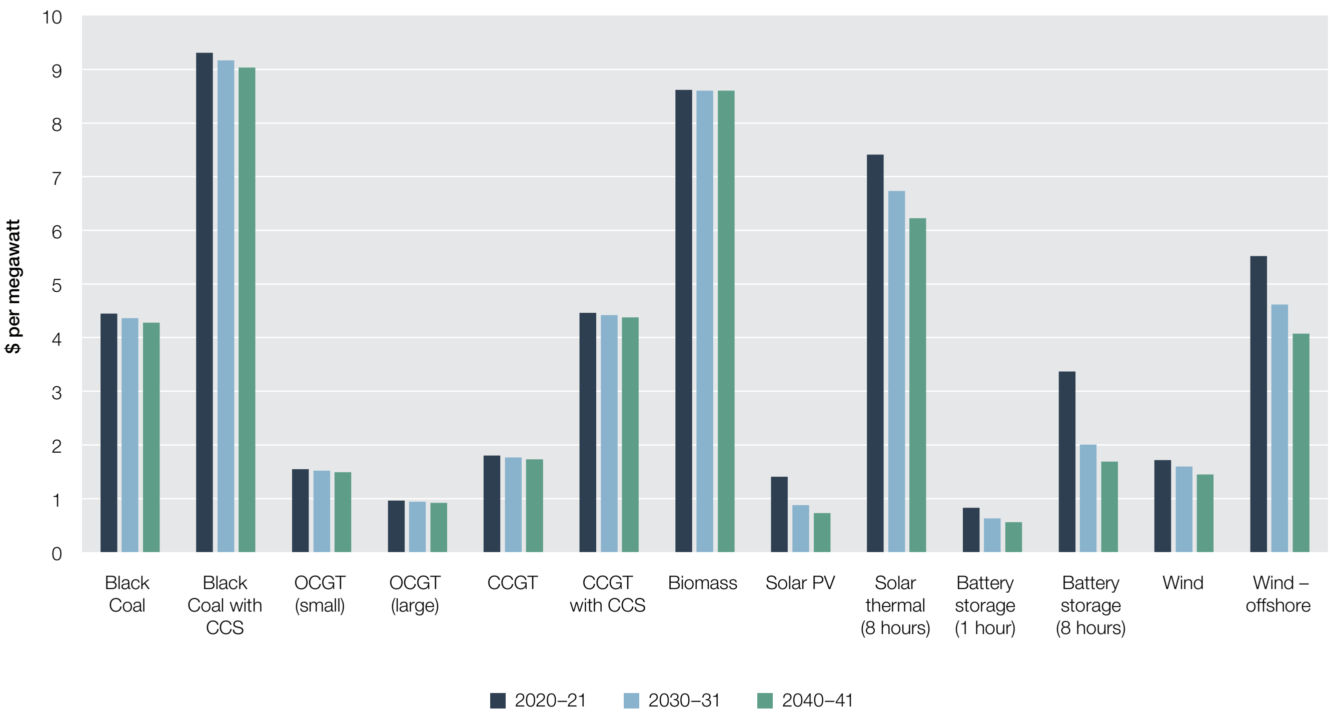
The International Renewable Energy Agency (IRENA) reported the global levelised cost of electricity (LCOE) of onshore wind generation fell by 38% between 2010 and 2019. Over the same period, it reported the global LCOE of large scale solar PV fell by 82%.[13]

In Australia, in December 2020 the Commonwealth Scientific and Industrial Research Organisation (CSIRO) estimated the LCOE in 2020 for large scale solar PV and onshore wind of around $45–70 per megawatt hour (MWh). They forecast the cost of onshore wind will continue to reduce marginally to 2040, but the cost of large scale solar PV will reduce by almost 50% in that time (figure 1.3).[14]

The substantial cost reductions for wind and solar technologies have made them the most economic options for new build generation and competitive with the operational costs of the current fleet of conventional generators. Factoring in storage and transmission costs needed to support up to 90% penetration of weather-dependent renewables, the CSIRO's upper cost estimate for wind and solar technologies was below $90 per MWh. In comparison, costs for new black coal and brown coal generation were estimated at $90–140 per MWh (and $170–300 for coal generation with carbon capture and storage). Gas generation was estimated at $70–120 per MWh. Both coal and gas plants face cost risks relating to fuel prices and uncertain carbon targets.[15]

Battery costs have also fallen. Bloomberg estimated lithium ion battery pack prices fell by around 89% between 2010 and 2020.[16] The CSIRO projected battery costs would fall by 24–40% between 2020 and 2030 (depending on battery size) and up to 50% by 2040 as global capacity for battery manufacturing rises to meet the demand for stationary storage and EVs.[17]

Figure 1.3 Forecast changes in generation capital costs



CCS: carbon capture and storage; CCGT: combined cycle gas turbine; OCGT: open cycle gas turbine; PV: photovoltaic.

Source: CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

13 IRENA, *Power generation costs*, IRENA website, accessed 22 April 2021.

14 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

15 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

16 Bloomberg New Energy Finance, *2020 battery price survey*, December 2020.

17 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

Economics of fossil fuel generation

The declining costs of renewable generation coincide with deteriorating economics for fossil fuel generation, making the latter less competitive in the market and changing their operating patterns:

- The rapid escalation of solar PV generation is lowering electricity demand during the day, reducing wholesale prices and revenues for coal fired generation at these times.
- The ageing of Australia's coal fired generation fleet is causing more frequent and longer unplanned outages and higher operating and maintenance costs.

An ageing coal fleet

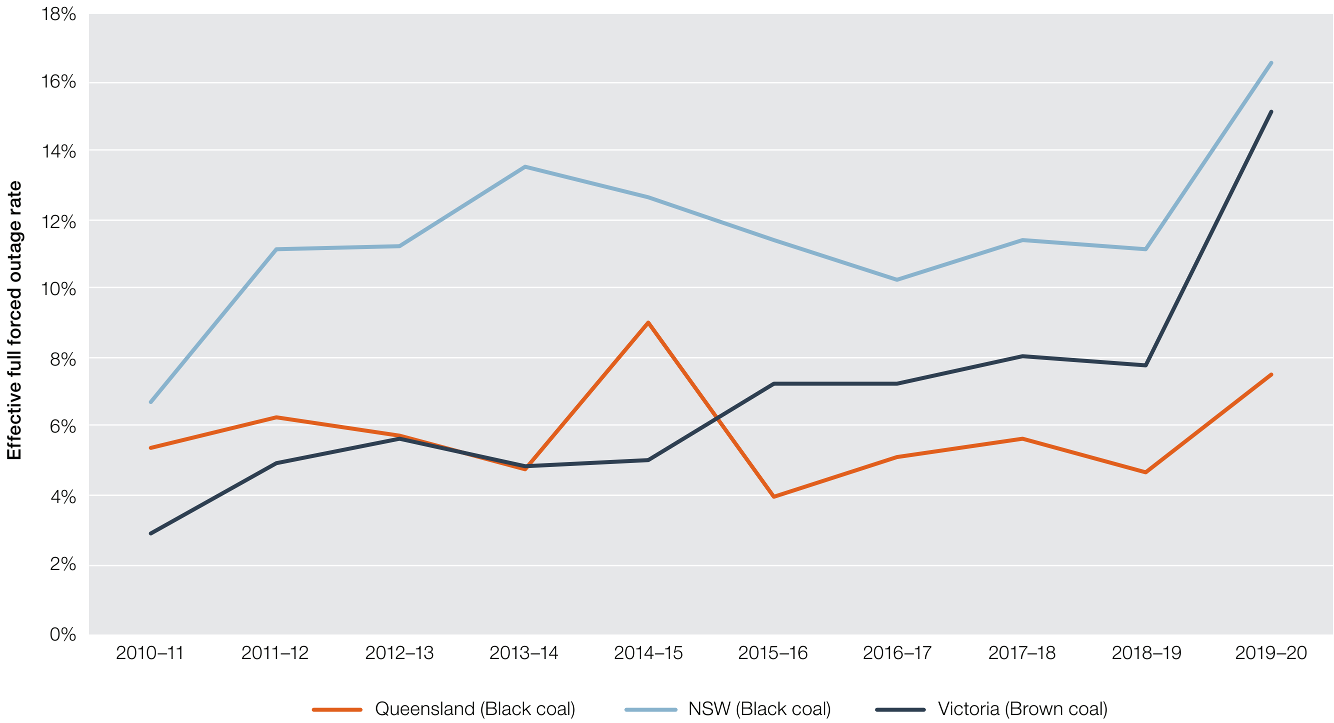
Australia's coal fired generators are ageing. Some have been retired and others are nearing the end of their economic life. Plant closures include Northern in South Australia (2016) and Hazelwood in Victoria (2017), which had become unprofitable due to rising maintenance costs and market penetration by other plant technologies. Further closures are scheduled in the coming years (section 1.2.1).

There are 18 remaining coal fired power stations in the NEM, with a median age of 35 years: 10 in Queensland (median age of 24 years), 5 in NSW (median age of 39 years) and 3 in Victoria (median age of 37 years).

In 2020 the Australian Energy Market Operator (AEMO) reported a trend of rising forced outages among fossil fuel plants due to breakdowns and more frequent and longer planned outages for maintenance and repair work.[18]

For each of the past 5 years, brown coal forced outage rates exceeded long term averages (figure 1.4). There was also a sharp increase in outages across black coal plants in NSW and Queensland in 2019–20.

Figure 1.4 Coal plant outages as a share of capacity



Source: AEMO, *2020 electricity statement of opportunities*, August 2020.

18 AEMO, *2020 electricity statement of opportunities*, August 2020.

Impacts of solar generation on fossil fuel plant

When rooftop solar PV generation is high in the middle of the day, the demand for electricity from the grid falls significantly (section 1.2.3). This phenomenon drives down prices at these times, challenging the economics and operating capability of coal fired generators, which are not engineered to run at low levels of output. Minimum demand remains sufficient to cover the minimum technical operating levels of most coal plant. But, if demand drops below those levels, coal plant operations may be significantly disrupted.

Origin and AGL announced plans to alter the operation of their Eraring and Bayswater plants (NSW) respectively in coming years. Options include shutting some generating units from mid-morning before firing them back up in the evening. This process represents a significant shift in the operation of these plants.

The ability of generators to operate more flexibly varies depending on plant age and condition. The increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, in an extreme scenario, earlier retirement.

In 2021 the Energy Security Board (ESB) noted that recent company results showed owners of large coal fuelled generators are facing commercial difficulties in the current wholesale market. It also noted falling wholesale energy prices may result in retirement decisions on some plants being brought forward. In 2021 EnergyAustralia announced it will retire its Yallourn power station in Victoria in 2028, 4 years earlier than planned.[19]

1.2 Dimensions of the transition

Features of the energy market transition include an evolving technology mix in the generation sector, a rapid uptake of DER, a changing geographical spread of energy resources and significant changes in electricity demand.

1.2.1 A changing generation mix

Since 2014 more than 4 GW of coal fired and gas powered generation left the market. Over this same period, around 12.5 GW of large scale wind and solar capacity and 8.5 GW of rooftop solar PV has begun operating.

This shift is continuing. Over the next 2 decades, another 16 GW of thermal generation (61% of the current coal fleet in the NEM) is expected to retire as plants reach the end of their economic lives. Over the same period, 26–50 GW of new large scale wind and solar capacity is forecast to come online, along with 13–24 GW of rooftop solar PV.[20] To balance this, the NEM will need 6–19 GW of new utility scale, flexible and dispatchable resources by 2040. To put these numbers into perspective, the average NEM demand is currently around 20 GW.[21]

Coal fired plant retirements

No significant coal fired generation has been added to the market since a 240 MW upgrade of Eraring power station in 2012. Since then, several major plants have closed, including Wallerawang (NSW), Hazelwood (Victoria) and Northern (South Australia).

Further closures are foreshadowed (figure 1.5). AGL plans to progressively retire its Liddell power station over the next 2 years. It plans to retire one of the plant's 4 units in April 2022 but close the 3 remaining units in April 2023 to support system reliability over the 2022–23 summer.[22] The plant supplies around 10% of NSW electricity, but declining reliability means it often runs at less than half its current rated capacity. AGL intends to replace the plant with a mix of renewable generation, gas peaking capacity, batteries, and an upgrade of its Bayswater power station.[23]

Planned closure dates for a number of other plants have been brought forward. In March 2021 EnergyAustralia announced it would bring forward the phased closure of its Yallourn brown coal generator from 2032 to 2028.[24] EnergyAustralia will partly offset the reduction in capacity by building a 350 MW, 4-hour battery by 2026.

19 EnergyAustralia, 'EnergyAustralia powers ahead with energy transition' [media release], 10 March 2021.

20 AEMO 2020 ISP – Central and Step Change Scenario – transmission and generation outlook files, cited by ESB, *Post 2025 market design options – a paper for consultation*, April 2021.

21 AEMO 2020 ISP – Central and Step Change Scenario – transmission and generation outlook files, cited by ESB, *Post 2025 market design options – a paper for consultation, part A*, April 2021.

22 AGL, 'Schedule for the closure of AGL plants in NSW and SA' [media release], 2 August 2019.

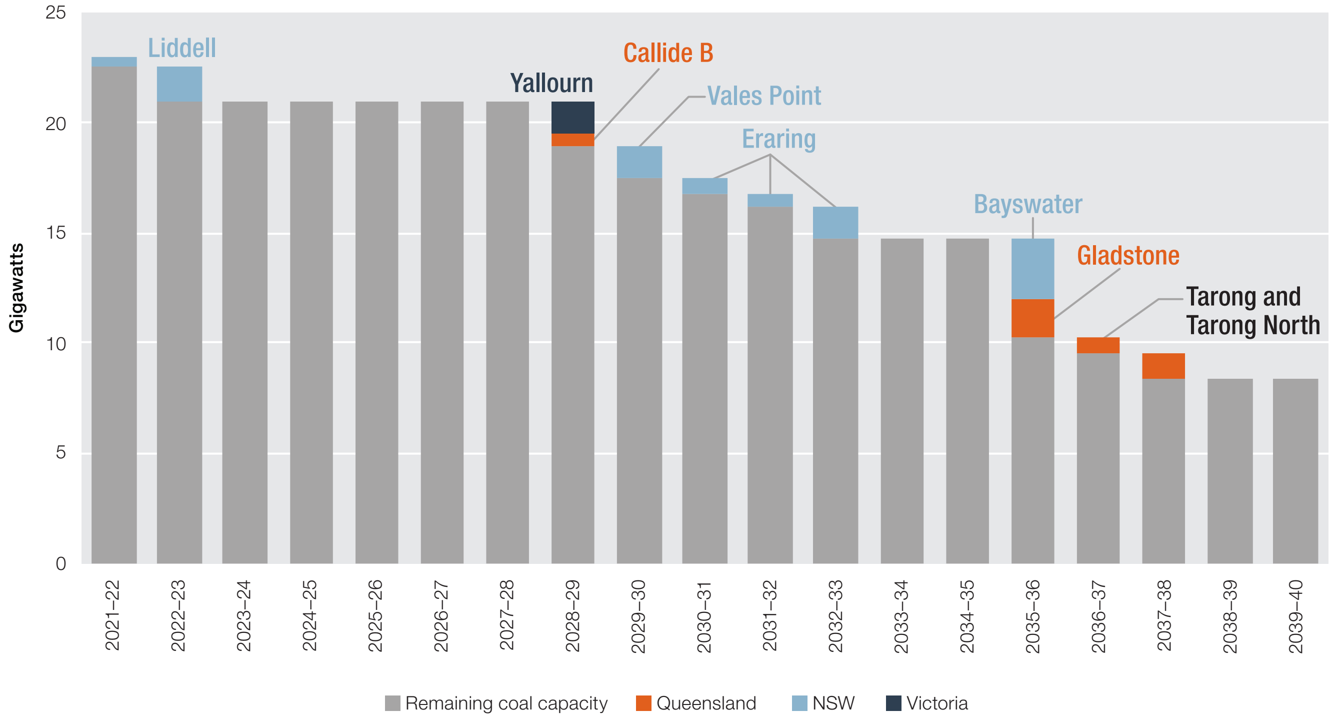
23 AGL, 'AGL announces plans for Liddell Power Station' [media release], 9 December 2017.

24 EnergyAustralia, 'EnergyAustralia powers ahead with energy transition' [media release], 10 March 2021.

AEMO forecast a further 11 GW of coal fired generation capacity in Queensland and NSW will retire between 2028 and 2038. Those closures would leave Mount Piper in NSW (1,320 MW) and Loy Yang A and B in Victoria (3,120 MW) as the NEM's last remaining coal fired power stations outside Queensland.

Despite plant closures, coal fired generation remains the dominant supply source in the NEM, meeting around 66% of energy requirements in 2020.[25] Utilisation rates of some remaining coal plants have risen to cover the supply gap left by the closures.

Figure 1.5 Scheduled closure profile of coal fired generators



Source: AEMO, *2020 Integrated System Plan*, July 2020. Data updated for recent market announcements.

Gas powered generation

Investment in gas powered generation over the past decade has been limited. AGL's 210 MW Barker Inlet power station in South Australia, commissioned in 2019 to replace its Torrens Island A power station (being progressively retired from 2020 to 2022), was the NEM's first new gas plant since 2011.

While gas powered generation output has reduced in recent years, it plays an increasingly important role in managing the variability of output from weather-dependant wind and solar plant. In the past, gas powered generation's critical role was to meet maximum summer demand, but it increasingly supports the market in winter when solar PV generation is lower and coal fired capacity tends to be withdrawn from the market for maintenance.[26]

Around 4 GW of gas powered generation is forecast to retire over the next 2 decades.[27] But multiple proposals for new gas plant are on the table in Queensland, NSW, Victoria and South australia. In May 2021 EnergyAustralia committed to developing a 316 MW gas plant in NSW by 2023–24. The Australian Government has signalled the need for new gas powered generation in NSW to fill the gap left by Liddell's exit and has backed a new 660 MW plant to be operated by Snowy Hydro in the Hunter region of NSW. It has also announced support for 2 gas plant proposals (in Queensland and Victoria), through its Underwriting New Generation Investment (UNGI) scheme (section 1.7.1).

25 Based on total generation (including rooftop solar PV) to meet electricity consumption.

26 AEMO, *Gas statement of opportunities 2021*, p 37.

27 AEMO, *2020 Integrated System Plan*, July 2020, p 44.

Weather-dependant renewable generation

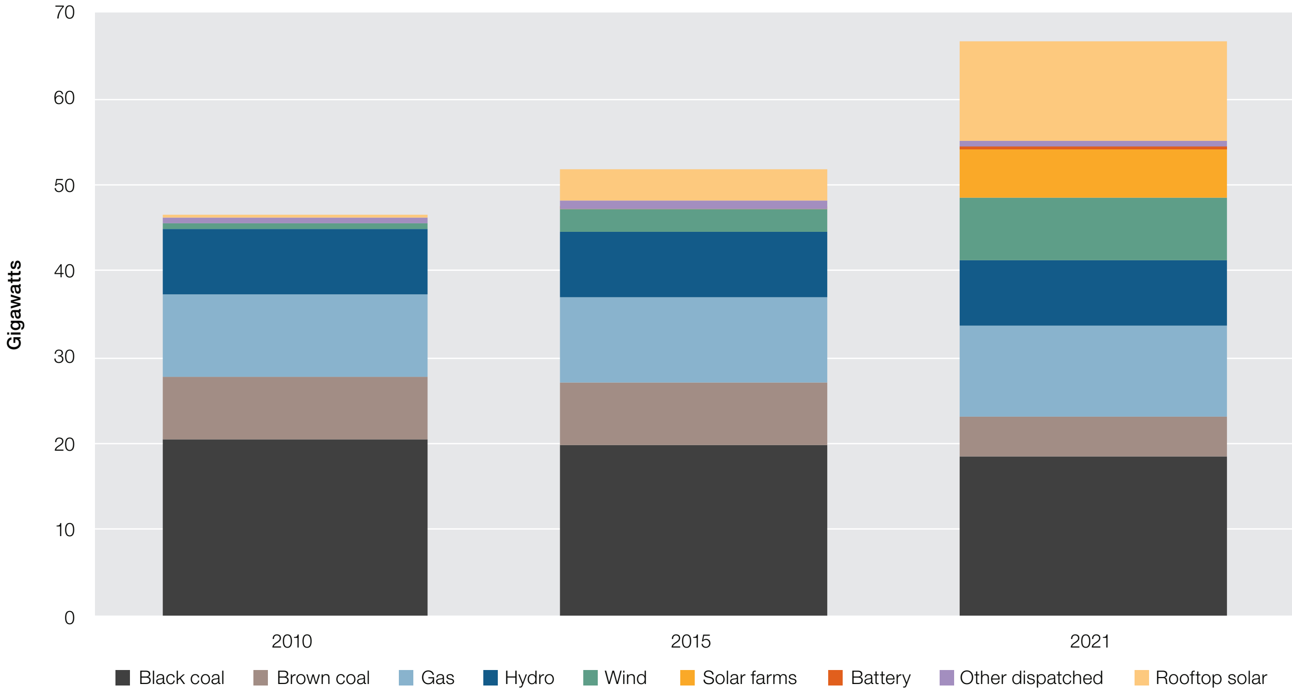
The decline in coal plant capacity since 2014 is in contrast to around 12,500 MW of weather-dependant renewable plant (mainly wind and large solar) coming online (figures 1.6 and 1.7). These technologies account for over 90% of proposed new generation investment. Figure 1.8 illustrates the impact of these shifts on the output of different plant technologies.

A feature of the transition is a shift away from the traditional model of having relatively few large power stations congregated close to fossil fuel sources towards having many small to medium generators spread out across the system. New solar and wind plants are being constructed in windy or sunny parts of the grid, but many of these locations are remote areas where the network capacity is limited.

Sections 1.5 and 1.6 discuss some challenges in managing this issue and solutions being developed.

While total capacity in the market has increased, renewable generators produce less energy for each MW of capacity installed than conventional plant because wind and solar plants can operate only when weather conditions are favourable. For every 1 MW of coal plant retiring, 2–3 MW of new renewable generation capacity is needed.[28]

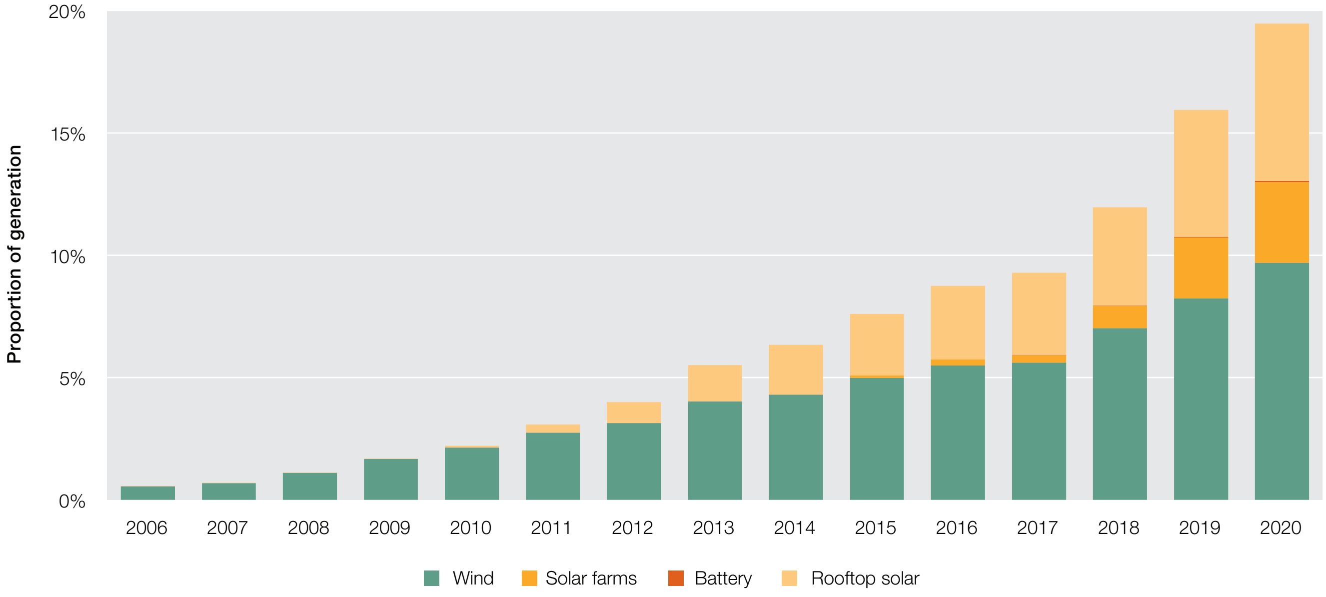
Figure 1.6 Generation capacity, by technology



Note: January (summer) capacity.
Source: AER; AEMO (data).

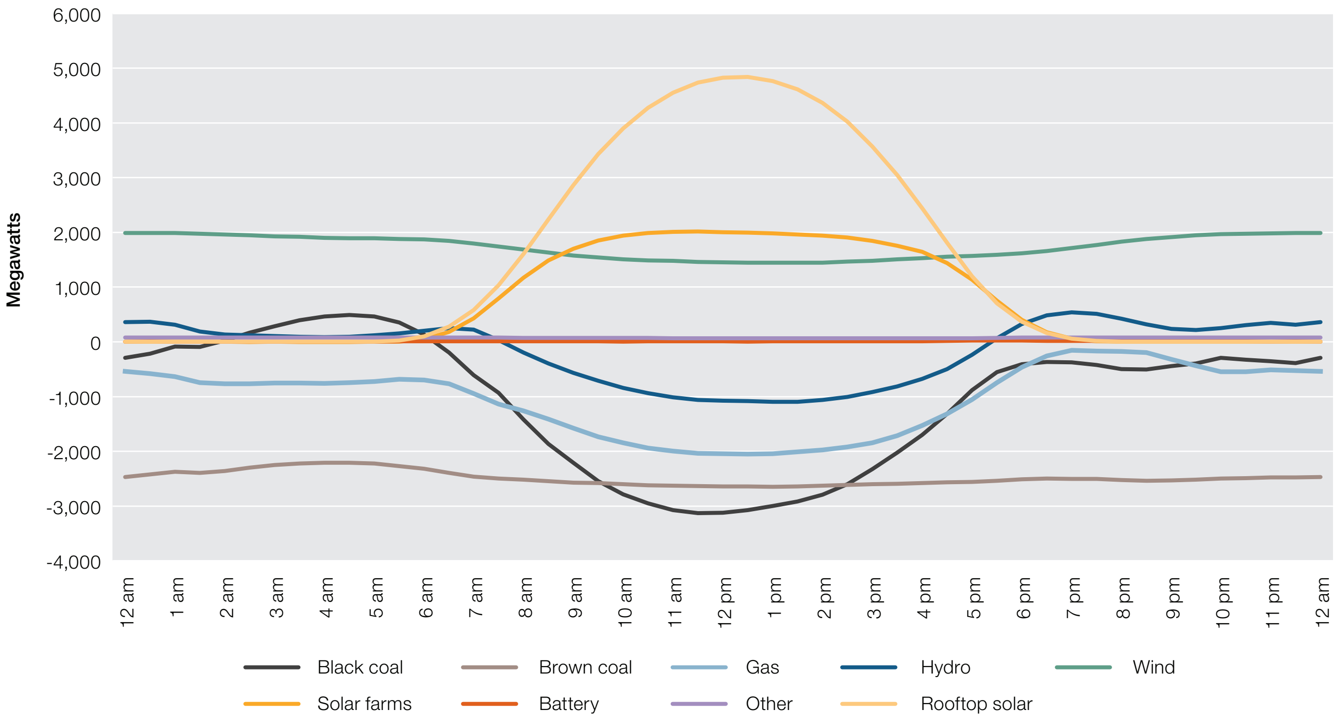
28 AEMO, *Draft 2020 Integrated System Plan*, December 2019.

Figure 1.7 Renewable generation in the National Electricity Market



Source: AER; AEMO (data).

Figure 1.8 Changing generation profile, by time of day, 2010–2020



Note: Comparison of average generation by time of day in 2010 and 2020. The 2010 rooftop PV generation is estimated using the average 2010 daily generation, allocated to intervals using 2020 proportions.

Source: AER; AEMO (data).

Volatility in supply and demand

Increased wind and solar generation in the NEM is creating more volatile supply and demand conditions. Since wind and solar generation relies upon specific weather conditions as a fuel source, its output is variable and can at times be difficult to predict. Solar production depends on the level of light received, so output is lower on cloudy days and in winter, when the days are shorter and the sun is lower in the sky. Wind production varies based on wind speed. By comparison, coal, gas and large hydroelectric generators can stockpile fuel for continuous use. While those plant technologies are also susceptible to outages or fuel shortages, their output when they are operating is more predictable and controllable.

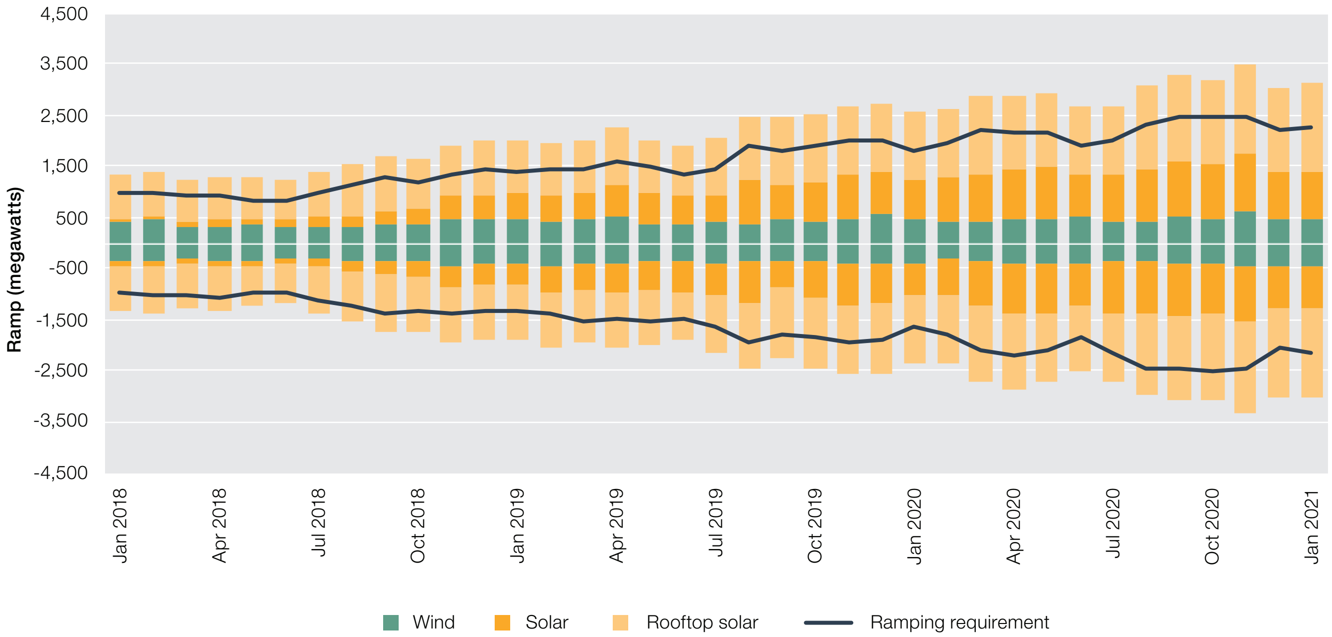
Wind and solar generators typically bid so they can generate when available, with more expensive sources of supply responding to their variability. Apart from variations caused by weather, renewable plant owners can also respond quickly to changes in economic signals (by, for example, switching off a plant if wholesale prices are too low).

As the contribution of weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators. Figure 1.9 illustrates the increasing scale of hourly changes in renewable output (ramping) in the NEM since 2018, which must be managed by equivalent changes in dispatchable generation or demand. This trend indicates the increasing opportunity for resources (generation, storage and demand response) that can respond quickly to these changes.

Fast-response alternatives are becoming critical to balance supply and demand in this volatile environment. Gas, hydro and batteries are able to respond to the variability of wind and solar because they can frequently alter output while continuing to remain economic. These technologies have been a focus of recent policies designed to stabilise the grid. Demand response can also play an important role in responding to sudden shifts in output from renewable generators.

Accuracy in demand and weather forecasting is critical. Recent work has focused on innovative short term weather forecasting systems for wind and solar generators.[29]

Figure 1.9 Hourly ramping of wind and solar generation



Note: Monthly top 1% of up and down 60 minute ramps in the National Electricity Market.
Source: AEMO, unpublished data.

29 ESB, *Health of the National Electricity Market 2019*, February 2020, p 34.

Grid scale storage

Storing electricity is becoming increasingly commercially viable. The growth in renewable generation is creating more commercial opportunities for storage to offer fast-response power system stabilisation services.

South Australia's Hornsdale battery, commissioned in 2017 and upgraded in 2020 (to 150 MW), was the first large scale battery in the NEM. A further 4 battery projects (totalling 110 MW) have since been commissioned across South Australia and Victoria, and over 7,400 MW of battery storage has been proposed (table 2.2 and figure 2.16). Some of these battery storage systems are located adjacent to solar and wind farms to smooth the contribution from these plants and respond to price opportunities.

Battery storage is currently largely used for shorter term 'fast burst' storage of energy to help stabilise technical issues in the grid (such as in providing frequency control services). The Australian Energy Regulator (AER) estimated batteries earned around $63 million in 2019–20 from frequency services. The Hornsdale battery earned the majority of this revenue ($58 million) – more than 15 times the battery's spot earnings from wholesale energy sales.[30]

Longer term, large scale storage is also being pursued through pumped hydroelectricity projects, which allow hydroelectric plant to reuse their limited water reserves. The technology involves pumping water into a raised reservoir when energy is cheap and releasing it to generate electricity when prices are higher. Pumped hydroelectric technology has operated in the NEM for some time in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven, 1,500 MW at Tumut 3 and 70 MW at Jindabyne). Increased market price volatility can provide opportunities to deploy this form of storage at a larger scale. Pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania respectively (section 1.7.2) and a number of smaller projects in NSW and South Australia.

Hydrogen

There is growing interest in Australia in hydrogen's potential to support the power system. Hydrogen production is an electricity-intensive process that can be quickly ramped up or down to manage fluctuations in renewable generation or provide frequency control ancillary services. Stored hydrogen can also be used as a fuel source for electricity production by flexible generators that offer electricity reliability and stability services.

In 2020 the Australian Government identified clean hydrogen as a priority low emissions technology, with a stretch goal of production under $2 per kilogram (around $15 per gigajoule).[31] It also announced support for 5 regional hydrogen hubs to build demand for clean hydrogen.[32] The CSIRO outlined opportunities for hydrogen to compete favourably on a cost basis by 2025 in Australian applications such as transport and remote area power systems.[33]

State governments are exploring opportunities to use or export hydrogen and ARENA is supporting a number of demonstration-scale renewable hydrogen projects and other hydrogen research.[34]

1.2.2 Distributed energy resources

Alongside the major shift occurring at grid level has been the uptake of small scale DER, which are consumer-owned devices that can generate or store electricity or actively manage energy demand. The growth of rooftop solar PV, the projected growth of battery storage and EVs and continued advances in load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners have the combined potential to revolutionise the way many customers receive and use energy.

These DER have varying characteristics – for example, rooftop solar systems are mostly passive and generate electricity only when the sun is shining, while active resources such as batteries and EVs can both draw electricity from, and inject it into, the electricity grid at any time.

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30 AER, *Wholesale electricity market performance report 2020*, December 2020.

31 DISER, *Technology Investment Roadmap: first low emissions technology statement – 2020*, September 2020.

32 The Hon Angus Taylor MP, Minister for Energy and Emissions Reduction, 'Jobs boost from new emissions reduction projects' [media release], 21 April 2021.

33 CSIRO, *National hydrogen roadmap*, August 2018.

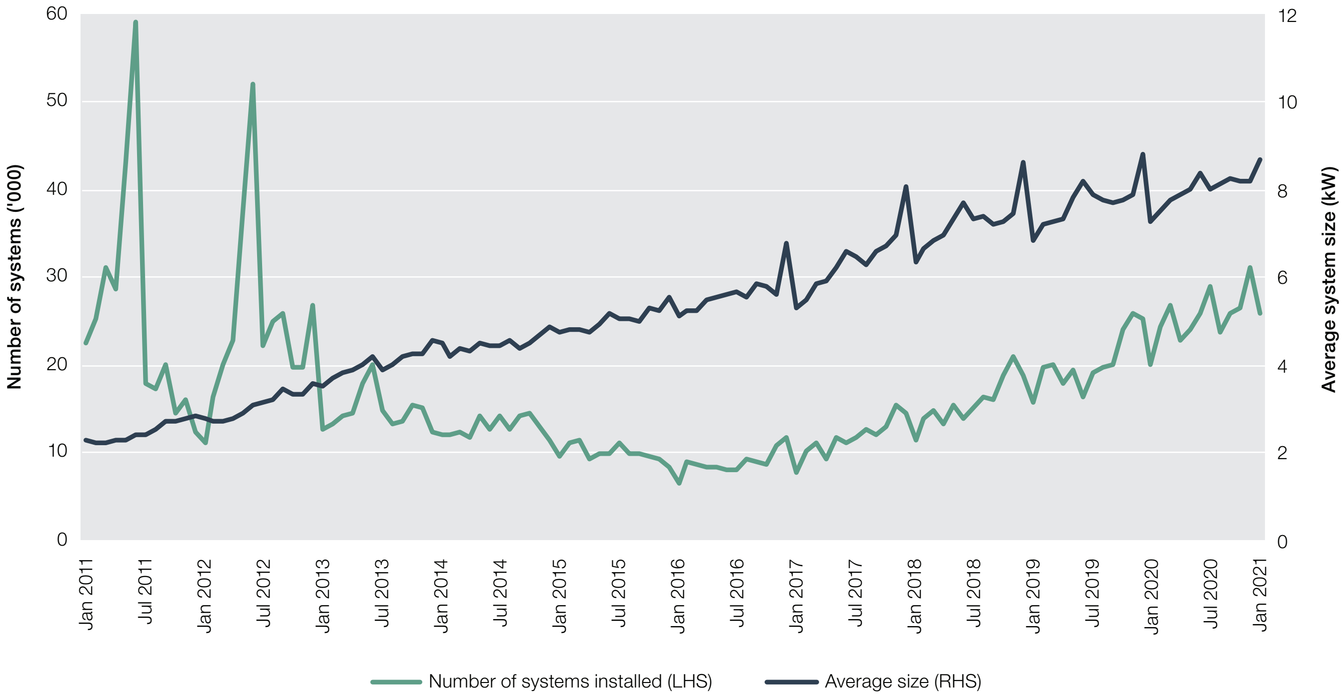
34 ARENA, *Hydrogen projects*, ARENA website, accessed 17 May 2021.

Rooftop solar photovoltaic installations

By far the fastest development has been in rooftop solar PV installations. Government incentives and declining installation costs have resulted in Australia having one of the world's highest per person rates of rooftop solar PV installation. Almost 24% of customers in the NEM partly meet their electricity needs through rooftop solar PV generation, and sell excess electricity back into the grid, compared with less than 0.2% of customers in 2007.[35] The combined capacity of these systems (11.4 GW) is around 17% of the NEM's total generation capacity and 4 times the size of the largest generator in the NEM (but dispersed through the country). Rooftop solar PV met 6.4% of the NEM's total electricity requirements in 2020.

Attractive premium feed-in tariffs offered by state governments drove the initial growth in solar PV installations. Despite the closure of those schemes, subsidies through the Australian Government's Small-scale Renewable Energy Scheme, combined with the falling costs of solar PV systems, has led to sustained strong demand for new installations. Total solar capacity installed in 2020 (2,470 MW) was 30% higher than the previous highest annual capacity in 2019, with both the number of systems installed (over 300,000) and the average system size (8.1 kilowatts (kW)) the highest recorded (figure 1.10).

Figure 1.10 Growth of solar photovoltaic installations in the National Electricity Market



Source: Clean Energy Regulator, *Postcode data for small scale installations, Small generation units—solar*, February 2021.

Batteries and electric vehicles

In coming years, customers will increasingly store surplus energy from solar PV systems in batteries and draw on it when needed. In this way, they will reduce their peak demand for electricity from the grid. The owners of DER can thus better control their electricity use and power bills, while taking initiative on environmental concerns. If DER is properly integrated with the power system, they could also help manage demand peaks and security issues in the grid (section 1.5.3).

But small scale batteries are not yet economic and uptake has been low. Of the 300,000 solar PV systems installed in the NEM in 2020, less than 3% had an attached battery system. The Clean Energy Regulator estimated customers in the NEM had installed 30,000 battery systems by February 2021.

35 Data on small generation units (solar) from Clean Energy Regulator, Postcode data for small scale installations, CER website, accessed 1 May 2021.

The charging profiles of EVs will affect power flows in a similar way to batteries. Price incentives that discourage customers from charging during peak demand periods would ease potential strain on the power system. The Australian Government predicts that EVs will make up 26% of new car sales by 2030, with 1.3 million in use by that date.[36] AEMO forecasts around half that number under current policy settings, with EVs comprising just over 1% of NEM demand by 2029–30.[37]

ARENA is funding different projects to assess different approaches to optimise the use of EVs. For example, in July 2020 ARENA announced funding for ActewAGL Retail (ACT) to demonstrate that a fleet of EVs can provide similar grid services to big batteries and virtual power plants. The EVs used in the trial can be charged from mains power or rooftop solar but can also send electricity back to the grid. In February 2021 Jemena (Victoria) announced funding for a number of networks across the NEM to explore using hardware-based smart charging for dynamic management of residential EVs.

Baringa Consulting estimated that effective integration of DER into the grid, through network tariff reform and direct procurement of network support services, would generate around $2.3 billion of value over the next 20 years from avoided network investment and reduced curtailment.[38]

Standalone power systems

It is increasingly plausible for customers to wholly bypass the traditional energy supply model by going 'off-grid' through self-sufficient solar PV generation and battery storage.

Standalone power systems (SAPS) or microgrids – where a community primarily uses locally sourced generation and does not rely on a connection to the main grid – are gaining traction in some areas. The systems typically comprise solar panels, a large battery and a backup diesel generator which can coordinate decisions on charging and discharging and operate independently of the electricity grid. The arrangements mainly occur in regional communities that are remote from existing networks, enabling them to lower costs and increase reliability while also reducing the costs other consumers incur in maintaining distribution network infrastructure.

A SAPS may be privately owned and operated or may be owned and operated by a distribution network. Either way, the system may be operated for profit or community benefit.

Reforms are being implemented to support the growth of off-grid arrangements. Changes to the National Electricity Law and National Energy Retail Law announced in 2021 will allow distribution network providers to offer SAPS (where economically efficient to do so) while maintaining appropriate consumer protections and service standards. The Australian Energy Market Commission (AEMC) expects to deliver implementation measures during 2021.[39]

There is likely to be an increased role for SAPS and microgrids in how distributors meet their supply obligations and manage emergency and fault events. For example, the AER is considering how SAPS and microgrids could be used to reduce bushfire risk and manage network infrastructure replacement at lower cost, with implications for how they should be regulated and the terms of access and pricing.[40]

To support the timely and efficient deployment of SAPS in the early stages of market development, in May 2021 the AER published a draft ring-fencing guideline that exempts distribution networks from ring-fencing requirements for generation services provided through SAPS (up to a revenue cap). While ring-fencing aims to provide a level playing field by preventing network businesses discriminating in favour of related affiliates in competitive markets, existing rules may impede development of SAPS in situations when there are likely to be limited third party providers of SAPS generation services.[41]

36 DISER, *Future Fuels Strategy: discussion paper*, February 2021.

37 AEMO, *2020 electricity statement of opportunities*, August 2020.

38 Baringa Consulting, *Potential network benefits from more efficient DER integration*, report for the ESB, June 2020. The estimate of network benefits is based on a central scenario. Benefits increase to around $11.3 billion under a step-change scenario.

39 AEMC, 'AEMC welcomes consultation on revised rules to support distributor-led stand-alone power systems' [media release], 25 March 2021.

40 Farrierswier, *Electricity network economic regulatory framework review 2020 – stakeholder interviews report*, 2020, p 16.

41 AER, *Draft electricity distribution ring-fencing guideline, explanatory statement*, May 2021.

Virtual power plants

Individually, DERs are largely invisible to the market and unable to participate in the wholesale market as a supplier of electricity unless they have sophisticated systems.

Virtual power plants (VPP) allow consumers with active forms of DER (such as battery storage, EVs or demand response) to aggregate with other providers at multiple points across the grid to coordinate decisions on charging and discharging. Aggregation creates opportunities for small scale resources to participate in markets such as those for demand management and frequency control services. A VPP (typically run by a retailer or aggregator) can bundle DER produced or stored electricity along with that of other consumers and then sell this energy.

Though most VPP projects in the NEM are relatively small, at around 5-10 MW of generation or storage capacity, AEMO anticipates up to 700 MW of VPP capacity by 2022.[42]

VPPs are mostly operated as part of trials to integrate the technology in to the NEM. AEMO has run virtual power plant demonstrations to test the technology's capabilities to deliver energy and grid stability services, the operational visibility of these arrangements, and the consumer experience.[43]

The Australian Renewable Energy Agency (ARENA) has provided funding to support trials of virtual power plants, including those run by AEMO. In 2019 ARENA provided funding to a trial by SA Power Networks to demonstrate how higher levels of energy exports from solar and battery systems can be enabled through dynamic, rather than fixed, export limits. In 2020 ARENA partially funded a trial led by Tesla to deploy 3,000 household solar and battery storage systems on residential properties owned by Housing SA. This is part of a larger project to connect up to 50,000 solar and battery systems across South Australia to form the world's largest VPP.

1.2.3 Changing patterns of electricity demand

As more electricity customers generate some of their own electricity needs through rooftop solar PV systems, the demand for grid-supplied electricity is changing. Output from rooftop solar PV systems met 6.4% of the electricity needs in the NEM in 2020 – up from 2.5% in 2015.

On 11 October 2020 South Australia operated for a period where over 100% of its regional demand was met by distributed and grid scale solar PV generation. Distributed solar PV alone met over 76% of regional demand for a few periods that day and over 70% for 4 hours. By 2025 other mainland NEM regions could be regularly operating close to or above 50% instantaneous penetration.

While solar generation is helping to meet energy demand, timing issues limit the extent of this assistance. In summer, daily energy use peaks in the late afternoon or early evening, when temperatures are high and business use overlaps with household use of air conditioning and other appliances. Winter demand peaks at a similar time of day, when households switch on heating appliances. Growth in rooftop solar PV has caused demand for grid-supplied electricity to peak later in the day. With peaks now occurring when solar output is low, scope for further support from solar PV may be limited. Rooftop solar PV systems met just 0.44% of electricity needs in the NEM at times of peak electricity consumption in 2020. The impact on peak demand was most pronounced (but still modest) in South Australia, with rooftop solar meeting 1.75% of peak electricity consumption. However, the impact of solar PV will typically be greater on the highest demand days over summer.

Rooftop solar PV generation is having a more profound impact on the level and timing of *minimum* demand for grid supplied electricity. Historically, demand reached its low point in the middle of the night, when most people are sleeping. But the growth in solar PV output in the middle of the day is lowering daytime grid demand, and minimum grid demand increasingly occurs then. Figure 1.11 shows how demand is falling in absolute terms, represented by the area under the curve, and how this shift is particularly apparent around midday. This hollowing out of demand through daylight hours is often called the 'duck curve'.

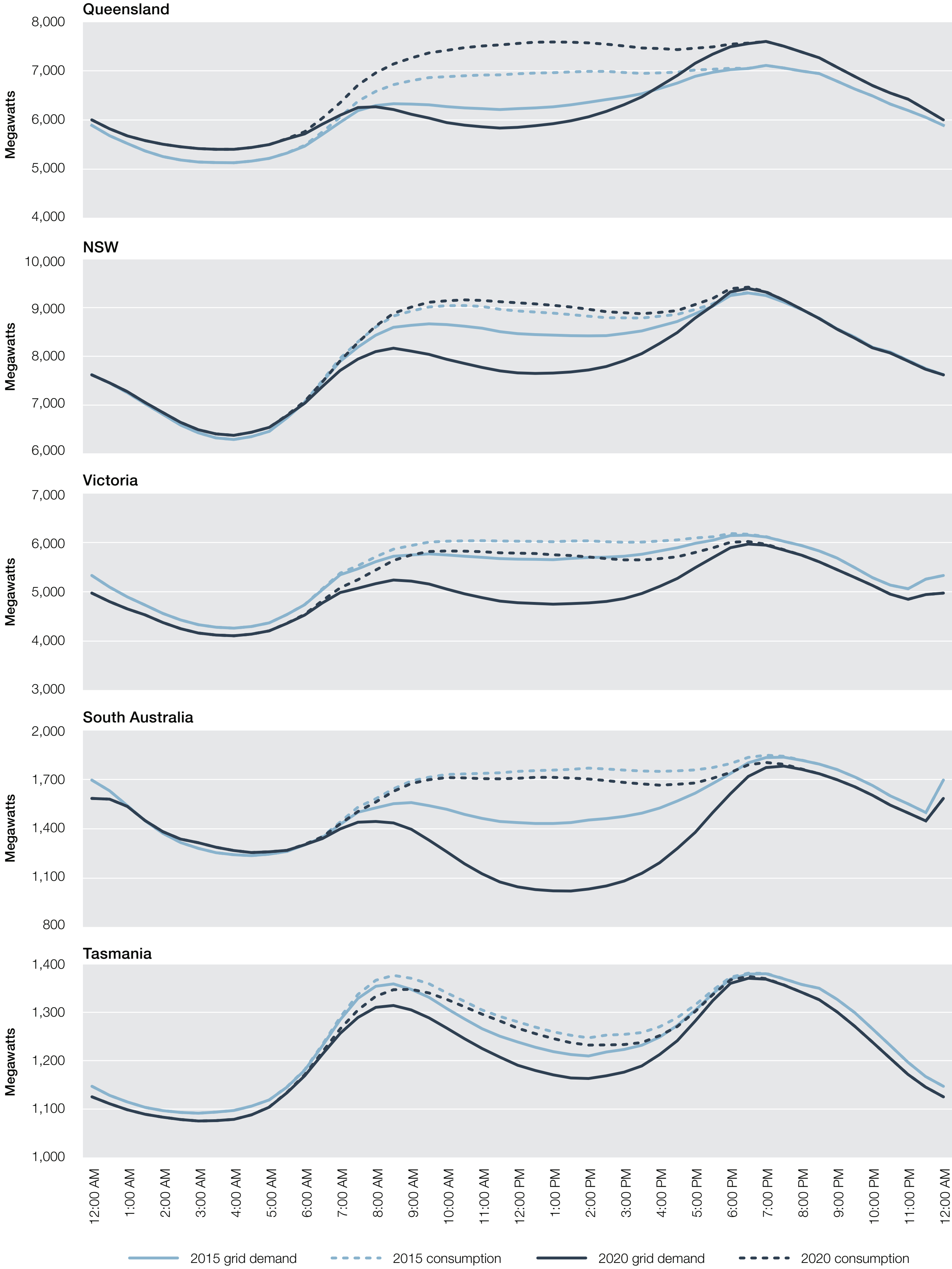
In 2020 midday demand in South Australia was almost 20% lower than the overnight demand. Rooftop solar PV systems in South Australia met over 40% of electricity needs at the time of minimum demand for grid supplied electricity in 2020. Increasing rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next few years.

Periods when grid demand drops to almost zero are posing serious challenges to the market operator in balancing supply and demand and maintaining the system in a secure operating state.

42 AEMO, *NEM virtual power plant (VPP) demonstrations program – consultation paper*, November 2018, p 3.

43 AEMO, *AEMO virtual power plant demonstrations, knowledge sharing report #3*, February 2021.

Figure 1.11 Electricity duck curves



Note: Average native demand by time of day for 2015 and 2020.

Source: AER; AEMO (data).

1.2.4 Climate change and the power system

Action on climate change was a key driver of the transition underway in the energy sector. But climatic changes already occurring are impacting electricity demand and the performance of generators and energy networks.

Australia's changing climate is creating more volatile patterns of electricity demand as the frequency of extreme heat events increases. Since maximum summer demand is driven by cooling (air conditioning) load, the warming Australian climate means demand peaks are rising relative to average levels of demand.

Extreme weather also stresses generation plant. Drought affects water storages and hydro generation capacity. Tasmania, for example, experienced a fall in water storage in 2015 and 2016. More recently, through 2018 and into 2019 many parts of Australia experienced low rainfall.

Higher ambient temperatures affect the technical performance of thermal plant (coal, gas and liquid fired plant) by reducing cooling efficiency. The performance of wind and solar plant and batteries may also degrade at higher temperatures.[44]

These issues are most frequent on very hot days when demand is at its highest. When AEMO notified the market about reliability threats in 2018–19, a number of thermal generators were not available, or running at lower capacity, as a result of technical or safety concerns from extreme weather events.[45] More recently, bushfires caused interruptions to the transmission grid over summer 2019–20 (section 2.6.2). Extreme wind also crippled transmission infrastructure in Victoria in early 2020.

The ESB's 2021 report on the health of the NEM highlighted that recent horrific bushfires continue to emphasise the importance of electricity system resilience as extreme weather events become more frequent and intense. The ESB argued this needs serious attention in the years ahead as further extreme events, including fire, flood and high temperatures, can be expected.[46] AEMO modelling is also factoring in the increased risk of extreme temperatures impacting peak demand and of drought affecting water supplies for hydro generation and cooling for thermal generation.[47]

Extreme weather also affects distribution networks, imposing costs that are passed on to energy customers. For example, in November 2020 the AER approved AusNet Services recouping $13.9 million from its customers to cover costs associated with the 2019–20 bushfires, which damaged 1,000 kilometres of power lines in its distribution network.[48] The AER also approved Ausgrid recouping $19 million from its consumers to cover costs associated with storms that hit Sydney in 2019–20 and damaged network infrastructure.[49]

1.3 Reliability issues

Reliability refers to the power system being able to supply enough electricity to meet customers' requirements (box 1.2). Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risk of system faults and outages.

1.3.1 Reliability in a transitioning market

The transition underway in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could once be relied on to operate when needed. As the contribution of weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators.

Reliability risks remain highest over summer, particularly at times when peak demand coincides with low renewable generation, or transmission or plant outages. AEMO has periodically intervened in the market to manage these risks (section 1.3.2).

44 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.

45 AEMC Reliability Panel, *2019 annual market performance review, final report*, March 2020.

46 ESB, *Health of the National Electricity Market 2020*, 2021, p 33.

47 AEMO, *2019 electricity statement of opportunities*, August 2019.

48 AusNet Services, *2019–2020 cost pass-through application – 2020 summer bushfires*, 27 May 2020.

49 Ausgrid, *2019–20 storm season pass through application*, 31 July 2020.

AEMO raised concerns the market would be at risk of generation shortfalls over recent summers, especially in Victoria and South Australia. But reliability forecasts improved for summer 2020–21 onwards, due to significant development of large-scale renewable resources, lower forecast peak demand, and minor generation and transmission augmentations.

AEMO forecast that unserved energy would rise in NSW in the period between Liddell closing in 2023 and Snowy 2.0 being commissioned.[50] But the amount of unserved energy is expected to remain below the reliability standard of 0.002%.

Box 1.2 How is reliability measured?

Reliability outcomes are measured in terms of unserved energy – that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. The Australian Energy Market Commission Reliability Panel sets the reliability standard for the generation and transmission sectors. The standard requires any shortfall in power supply to not exceed 0.002% of total electricity requirements. It has rarely been breached, but the Australian Energy Market Operator (AEMO) increasingly intervenes in the market to manage forecast supply shortfalls.

The standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Around 95% of a typical customer's power outages originate in distribution networks and are caused by local power line and substation issues. While these outages are common, their impact is confined to relatively small cluster of customers in each instance. Section 3.15.3 of this report covers distribution reliability.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage.

While the 0.002% target for unserved energy is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability standard is used in planning to trigger market mechanisms to prevent forecast supply shortages. The interim targets allows AEMO to trigger the Reliability and Emergency Reserve Trader (section 2.9.1) and Retailer Reliability Obligation (box 1.3) if unserved energy is forecast to exceed 0.0006%.

1.3.2 Managing reliability risks

AEMO has powers to intervene to manage a forecast lack of supply to meet electricity demand. Over the past 4 summers (up to and including 2020–21), it used the Reliability and Emergency Reserve Trader (RERT) mechanism to manage reliability risks. Under the scheme, AEMO secures contracts with generators (to provide capacity) and/or large customers (to reduce their consumption) when the power system is under stress.

Before 2017–18, the RERT had been used to procure backup capacity on only 3 occasions and was never activated. AEMO activated the RERT for the first time in November 2017 to manage a forecast lack of reserves in Victoria; and a further 6 times in Victoria and South Australia over the 2017–18, 2018–19 and 2019–20 summer periods.

The RERT was activated in NSW for the first time in January 2020, where it was activated on 3 separate occasions. AEMO activated RERT reserves once more in NSW, in December 2020. The RERT was activated in Queensland for the first time in May 2021, following a serious fire at the Callide C power station. The cumulative cost of the RERT between 2017 and 2020 was around $110 million. Market reliability outcomes are discussed in section 2.9.

1.3.3 Market reforms on reliability

The ESB is exploring how best to manage reliability risks in an evolving energy market through the NEM 2025 project. In doing so, it is looking at mechanisms that provide long term signals for investment in resources with flexibility to manage sudden demand or supply fluctuations and which can deliver an orderly closure of ageing generation.

50 AEMO, *2020 electricity statement of opportunities*, August 2020.

The ESB's reforms are occurring at a time when the fast moving nature of the transition is creating a level of uncertainty that impacts on participants' willingness to invest in dispatchable resources. Uncertainty is heightened in relation to technology costs, the timing of large scale generation closure, and the ability of retailers to hedge demand risk. While some new investment is being supported by government led initiatives (section 1.7), these can dampen investment signals sent by the NEM spot and contracting markets.

These factors reflect a need for the ESB to consider the adequacy of existing investment signals in the NEM. The ESB is focused on reforms that ensure sufficient dispatchable resources and storage capacity are in place prior to anticipated plant closures and that generator exit does not cause significant price or reliability shocks to consumers.

Key areas being considered by the ESB are changes to the Retailer Reliability Obligation (RRO) scheme (box 1.3), and a NEM-wide approach to integrating jurisdictional underwriting or schemes for new investment. The ESB released a consultation paper on its preferred approaches to reform in April 2021, with recommendations to ministers expected to follow later in the year.[51]

Other recent reforms to policy setting and market rules that have targeted the market's ability to respond to reliability risks include:

- requirements on plant owners to give notice of closure.
- stricter rules for wind and solar plants
- changes to the RERT scheme
- expanding the role of demand response.

Stricter rules for wind and solar plants

The rising incidence of negative spot prices in South Australia and Victoria is encouraging wind and solar farms to curtail their plant for economic reasons, even though weather conditions to operate were suitable. Economic self-curtailment was greater than plant curtailment by AEMO in the first (summer) quarter of 2021, accounting for 58% of all curtailment across the market (by MW).[52]

In response to an AER proposal, in March 2021 the AEMC amended the rules to require semi-scheduled generators (commercial wind and solar plants) to generate according to the available resource and their offer and not turn off without receiving an instruction from the market operator.[53] By requiring semi-scheduled generators to operate in this way, AEMO can more effectively forecast demand and supply and avoid unexpected impacts to system security.[54]

Notice of closure

Since September 2019 generators are obliged to provide the market at least 42 months advance notice of their intention to close. The rule aims to improve long term forecasting of plant closures and reduce the reliability risks that closures can impose. When the rule commenced, a number of generators provided formal notice of their impending closure, including AGL Energy's Liddell and Torrens Island A power stations; and Stanwell's Mackay gas turbine.

The ESB raised concerns in 2021 that the 42-month rule may be insufficient to address reliability risks. It found there may be value in widening the notification rule to cover situations other than plant retirements; for example, significant changes in operation such as mothballing of generator units, as well as changes in contractual positions. It also noted the notice of closure requirements does not address risks arising from the sudden exit of thermal plant – for example, due to catastrophic technical failure.[55]

To address these concerns, the ESB is exploring mechanisms for a more orderly exit of thermal plants as they retire from the system – such as changes to notice of closure requirements, expanding information requirements around mothballing and seasonal shutdowns of generators, regulated or negotiated arrangements with thermal plants for their closure, and contingent scenario planning (such as the Australian Government's Liddell Taskforce, which was established in 2019 to assess the impacts of the planned closure of that plant).[56]

51 ESB, *Post 2025 market design options – a paper for consultation*, April 2021.

52 AEMO, *Quarterly energy dynamics, Q1 2021*, April 2021.

53 AEMC, *Semi-scheduled generator dispatch obligations*, information sheet, March 2021.

54 AER, 'AER requests fast track consideration of proposed rule change to address system security' [media release], 30 September 2020.

55 ESB, *Post-2025 market design directions paper*, January 2021, p 32.

56 ESB, *Post-2025 market design directions paper*, January 2021.

Box 1.3 Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) scheme (launched in July 2019) creates incentives for retailers and large energy customers to purchase contracts that should support investment in dispatchable electricity generation in regions where a gap between generation and peak demand is forecast. The Australian Energy Retailer (AER) publishes guidelines on the scheme's operation.

The RRO scheme supports reliability by requiring retailers and large energy users to enter contracts (or own generation capacity) to match their electricity demand in periods when the Australian Energy Market Operator (AEMO) forecasts a reliability gap between generation and peak demand. If a material gap is determined 3 years out then AEMO will ask the AER to formally trigger the RRO. The trigger level is intended to ensure the electricity system remains reliable during a one-in-10-year summer. In November 2020 the Energy Security Board (ESB) reduced the trigger for activating the RRO (to a forecast of 0.0006% unserved energy – down from 0.002%).[57]

Once the RRO is triggered, electricity retailers and large energy users (liable entities) are on notice to secure contracts for sufficient generation to cover their expected demand for grid-supplied electricity, based on a one-in-2-year peak demand forecast. Demand response contracts qualify if they are 'in market' and have a direct link to the electricity market to manage exposure to high spot prices.

To support contract market liquidity, a market liquidity obligation (MLO) operates when the RRO is triggered. The MLO requires large generators to perform a 'market maker' role by offering to buy and sell hedge contracts on the Australian Securities Exchange (ASX) or other approved platform with a limited price spread. The obligation aims to ensure smaller participants can access enough contracts to meet their RRO obligations. The AER monitors relevant generators' compliance with the MLO.

If a forecast gap persists one year out then liable entities must submit their contract position to the AER. AEMO may also procure emergency reserves through the Reliability and Emergency Reserve Trader mechanism to address any remaining supply gap. If actual peak demand exceeds the forecast, the AER must assess liable entities' contract positions against their share of system load. Entities without adequate contracts will be required to contribute to the cost of AEMO procuring emergency reserves.

In 2020 AEMO identified a potential supply shortfall in 2023–24 in NSW, triggering the RRO (section 2.7.3).

As part of its NEM 2025 reforms, the ESB is exploring options to enhance the RRO mechanism to ensure retailers implement and maintain supply arrangements with new and existing resources sufficient to meet their customers' needs. The ESB noted that the current RRO provides only muted signals for timely investment, with compliance assessed only if a number of hurdles relating to AEMO forecasts are passed.[58]

The ESB is developing 3 options for modifying the RRO:

- removing the 3-year-out trigger to extend the duration of the price signal for investment and promote more contracting by retailers
- requiring retailers and large loads to meet their RRO targets by acquiring physical certificates rather than hedge contracts. This approach creates an investment signal and a revenue stream that is separate from spot and contract market prices
- allowing state Energy Minsters to trigger the MLO without AEMO identifying a gap.

It is also considering issues around the RRO's complexity and compliance burden.

South Australia

The operation of the RRO differs in South Australia compared with other regions, in that the state Energy Minister can trigger the obligation.

The minister triggered the RRO in South Australia for periods in the first quarters of 2022, 2023 and 2024. The 2022 RRO period was subsequently closed, as AEMO did not identify an enduring reliability gap 1 year ahead.

57 ESB, *Interim reliability measures – RRO trigger, recommendation for National Electricity Amendment (Retailer Reliability Obligation Trigger) Rule 2020*, decision paper, October 2020.

58 ESB, *Health of the National Electricity Market 2020*, 2021, pp 24–25.

Reliability and Emergency Reserve Trader changes

From March 2020 AEMO can contract for RERT resources up to 12 months in advance (previously 9 months in advance).

In August 2020 a rule change by the ESB established a temporary out of market capacity reserve (the Interim Reliability Reserve) that reduces the threshold for procuring capacity under the RERT. Under the Interim Reliability Reserve, in place until March 2025, AEMO can contract for RERT resources between 10 weeks and 12 months in advance if unserved energy in a region is forecast to exceed 0.0006% (compared with the normal reliability standard of 0.002%).

AEMO can enter into reserve contracts of up to 3 years where there is a forecast reliability shortfall in at least 2 of the 3 years. This scheme replaced Victorian specific RERT arrangements introduced in 2020 that allowed for multi-year RERT contracts to help address reliability challenges facing that state.

Expanded role for demand response

While many reforms targeting reliability have focused on the supply side, reforms are also progressing on the demand side to ease reliability risks. Demand response relates to electricity users responding to financial incentives to cut their energy use from the grid temporarily when the power system is under pressure.

New technologies are providing opportunities for smaller scale DER to offer demand response in the wholesale market (and in markets for grid stability services). Initiatives include virtual power plant trials (section 1.2.2) and a proposed AEMO-operated platform on which participants can contract for electricity in the week leading up to dispatch to enable more demand response.

While demand response can help manage peak demand, it has not been widely used in the NEM. One reason is that only retailers and large industrial customers see the price signals that encourage demand response, and they often prefer to manage this risk through hedge contracts.

Reforms that apply from October 2021 aim to attract more demand response providers into the market.[59] Under the reform, customers can offer demand reductions through AEMO's central dispatch process and be paid for whatever load they are called on to reduce. The mechanism will initially be limited to large customers.

The AEMC regards the mechanism as an interim measure in the transition to a 2-sided market with participants on both the supply and demand sides participating in dispatch and price setting. The ESB is developing a 2-sided market as part of the NEM 2025 framework (section 1.5.7).

1.4 Power system security

Power system security relates to maintaining the power system within technical operating limits needed to keep it safe and stable. Parameters of system security include frequency and voltage stability; and physical properties such as system strength and inertia (box 1.4). An electricity system that operates outside acceptable limits for these parameters may jeopardise safety, damage equipment (both network assets and household appliances) and cause blackouts. A secure system needs to be able to withstand a credible disturbance (such as the loss of a major transmission line) by quickly returning to a secure operating state.

System security differs from reliability, but the distinction can sometimes blur. For example, if electricity demand is forecast to exceed available supply (a reliability issue) then the imbalance may also affect the power system's frequency (a security issue). There is also a temporal distinction. Reliability is typically a longer term consideration, while security issues tend to occur closer to real time.

59 AEMC, *National Electricity Amendment (wholesale demand response mechanism) Rule 2020, rule determination*, June 2020.

1.4.1 Security in a transitioning market

The energy market transition impacts system security on many levels. Traditional synchronous generators like coal, gas and hydro plants use spinning turbines that create physical properties called inertia and system strength as a normal by-product of producing energy. These properties play an important role in keeping the power system stable and secure. In the past, these properties were taken for granted and considered 'free' services.

But, as older synchronous plants retire, important sources of inertia and system strength are disappearing from the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltage stable. The retirement of synchronous generation is also causing situations where too much reactive power is injected (particularly at times of high renewable output), causing overvoltage.

Wind and solar generators are not synchronised to the frequency of the power system. To connect with the system, they use a synthetic power device called an inverter, which converts the DC current generated by wind and solar plants to the AC current operating in the grid.

The transition to a more renewable generation mix poses twin challenges to system security. First, inverter based resources like wind, solar PV and batteries have only recently been configured to support frequency control and provide system strength in the same way as coal, gas and hydro plant. But more work is required to procure and integrate these services from inverters. Second, those resources require system strength to ride through faults and meet performance standards.

The rising proportion of wind and solar in the generation mix has contributed to more periods of low inertia, weak system strength, volatile frequency and voltage instability, although remedial actions are being taken. The amount of time the power system frequency spent away from the target frequency of 50 Hertz (Hz) rose between 2016 and 2020. AEMO identified this degradation as being driven by a decline in the responsiveness of generation plant to system frequency combined with an increase in the variability of generation and load in the power system (section 1.4.4).[60]

Since the closure of South Australia's Northern power station in 2016, and new entry of wind and solar plant, *inertia* shortfalls have caused more volatile frequency disturbances in the state. In 2018 AEMO declared an inertia shortfall in South Australia. Inertia levels have also fallen in Victoria since the closure of its Hazelwood power station in March 2017, falling at times below acceptable thresholds (box 1.5). The ESB reported that, by 2025, inertia levels on the mainland could drop by 35% compared to its historical average. This will increase the need for frequency services following a disruption.[61]

System strength has become an issue across the fringes of the grid, making it harder for new generators to connect. AEMO has declared system strength gaps and worked with local transmission networks to address shortfalls in South Australia, Tasmania, north west Victoria and north Queensland (section 1.4.5 and box 1.5). The uptake of DER is creating similar issues in distribution networks (section 1.5).

A lack of system strength in parts of the system in recent years has meant that some renewable generators are being constrained off and others have been unable to connect to the grid in a timely manner. The AEMC is considering rule changes that would facilitate the introduction of system strength services in the NEM.

The rising proportion of wind and solar plant also raises challenges to the generation fleet's ability to *ramp* (adjust) quickly to sudden changes in renewable output. The magnitude of peak ramps (upward/downward fluctuations in supply) from renewable generation almost doubled between 2018 and 2020 (figure 1.8). Accurate forecasting of expected ramps is difficult, raising uncertainty and creating a need for greater ramping reserves as wind and solar penetration increases.

Generator ramping capability will be better recognised and rewarded when the settlement period for the electricity spot price changes from 30 minutes to 5 minutes from October 2021. This reform will provide stronger price signals for flexible generation.[62] Similar to system strength, the AEMC is also considering a rule change for the introduction of an operating reserve which is intended to create a market that would address ramping issues.

60 AEMO, *Primary frequency response incentive arrangements, rule change proposal*, 3 July 2019, p 14.

61 ESB, *Health of the National Electricity Market 2020*, 2021, p 28.

62 The reform was originally scheduled to commence from July 2021. In April 2020 AEMO proposed the delay in response to the potential impact of COVID-19 on the energy industry to free up human and financial resources that would be under strain during the pandemic.

Box 1.4 Power system security

Power system security has a number of parameters, including frequency stability, inertia, voltage stability and system strength.

The power system's *frequency* refers to the rate of oscillations as electricity transmits through the system. Generators require a narrow band of system frequency to operate safely and efficiently. In the National Electricity Market (NEM), the frequency target is 50 cycles per second, or 50 Hertz. Sudden shifts in supply or demand can push frequency away from this level. In the NEM, temporary deviations within 49.85–50.15 Hertz are considered acceptable. Wider deviations, or rapid changes of frequency, can lead to system failures.

Synchronous generators (such as coal, gas and hydro plants) produce *inertia* – a physical resistance that slows the impact of a sudden disturbance to the system. The large rotating mass of a plant's turbine and alternator create this inertia as they rotate in synch with system frequency. A system with low inertia has a higher risk that frequency deviations will cause generators to disconnect from the power system.

System strength is an umbrella term referring to the power system's resilience to voltage changes caused by a system fault. *Voltage* is the electrical force or pressure between 2 points that 'pushes' an electric charge through a wire. Voltage stability is necessary for a healthy power system to push power around the system in a steady, controlled manner. A strong, stable voltage helps protection systems locate and clear faults, such as those caused by plant malfunctions or by threats such as lightning and bushfires. In a strong system, reactive power is injected and absorbed to manage these fluctuations. Wind and solar plants need a smooth and stable voltage wave form to operate properly, so diminishing system strength makes it harder for them to connect to the grid.

The energy market transition is weakening system strength in the NEM. Like inertia, synchronous coal, gas and hydroelectric generators create system strength through the normal spinning operation of their turbines. But newer plant like batteries, wind and solar use electronics – computers and inverters – rather than turbines to couple with the grid.

Technology solutions

As the generation mix changes, new approaches are needed to provide essential system services. The capability of wind and solar plants to provide these services is evolving, as are the types of service required. The first wave of wind farms in particular were not configured to provide security services. However, advanced inverter technologies have the capability to respond rapidly to sudden changes in electricity supply or demand and to make a contribution to system strength.

Other technology solutions include synchronous condensers – that is, large spinning machines similar to the spinning motion in synchronous generators but not driven by the action of a turbine. The rotation of these machines provides inertia and can aid in maintaining voltage stability (section 1.4.3). Smart transmission lines are another approach for energy networks to resist voltage disturbances. Some recently installed renewable plant, and storage solutions including grid scale batteries, pumped hydro and virtual power plants, can also provide services to manage voltage fluctuations and strengthen the network.

Managing system security

AEMO is responsible for managing power system security in the NEM. It uses market-based methods where possible, but it overrides the market's normal operation if market measures are inadequate. The AEMC assesses market rule changes to address systemic issues. A number of recent rule changes target security issues.

At a higher level, the ESB is reviewing the market's architecture as a whole to ensure it meets the requirements of the evolving market. It is scoping reform in conjunction with other agencies, including AEMC rule change processes to introduce of a range of new system security services such as system strength and fast frequency response services.

1.4.2 Market intervention to manage security

Where possible, AEMO operates markets to procure essential system services needed to maintain power system security. To date, these markets exist only for a number of frequency control services. There are currently no market arrangements to procure system strength or inertia (collectively referred to as synchronous services) in the NEM. In the past, these properties were so plentiful that no value was placed on them and no mechanism to procure or schedule them was required.

Where no market exists, or if market solutions are inadequate, AEMO may intervene in the market to manage a security issue. Interventions may be aimed at removing the source of the problem (for example, constraining a generator causing the issue from operating) or creating a solution (for example, directing a generator that may help the situation to operate).

While sometimes necessary as a short term measure, this intervention is costly and ultimately paid for by consumers. It is not sustainable as a long term solution. Policy and rule reforms are progressing to provide longer term solutions.

Key requirements for AEMO to effectively intervene in the market are visibility of participants and an understanding of how participants will respond to market events. In 2019, following an investigation of the circumstances of the 'black system' event in 2016, the AER brought proceedings in the Federal Court against 4 wind farm operators in South Australia for allegedly failing to comply with generator performance standards; and proceedings against the Pelican Point gas power station (South Australia) for allegedly failing to submit accurate generator availability information.

In February 2021 CS Energy paid penalties totalling $200,000 for allegedly failing to ensure it was able to comply with its market offers for frequency control services. CS Energy also repaid to AEMO around $1 million it received as payment to provide the services.

Intervention methods

AEMO normally dispatches the lowest cost generators to meet demand, but this dispatch can cause security issues. In these circumstances it may intervene to override the market's normal efficient operation.

For example, if a lack of online synchronous generators causes a lack of inertia and system strength then AEMO may direct one or more synchronous generators to operate, even if it is uneconomic for the plant owners to do so. It may also constrain non-synchronous generators (wind and solar) from operating to ease a drain on system strength and allow the directed synchronous machines to fill the supply gap. On some occasions, it might de-energise transmission lines to change power flows or switch off rooftop solar PV to increase grid demand to address an issue.

The mechanisms can be applied jointly. In South Australia, for example, AEMO has managed weak inertia and system strength by switching off (constraining) wind and solar generators to ease the drain on system strength, while simultaneously directing synchronous gas generators to operate (to create inertia and boost system strength). In Victoria and Queensland it has managed voltage and system strength issues by directing gas plants to operate while simultaneously de-energising a number of transmission lines.

Market interventions to maintain system security have risen sharply in recent years, at significant cost to consumers. South Australia and, more recently, Victoria, Tasmania and Queensland have been the focus of these interventions.

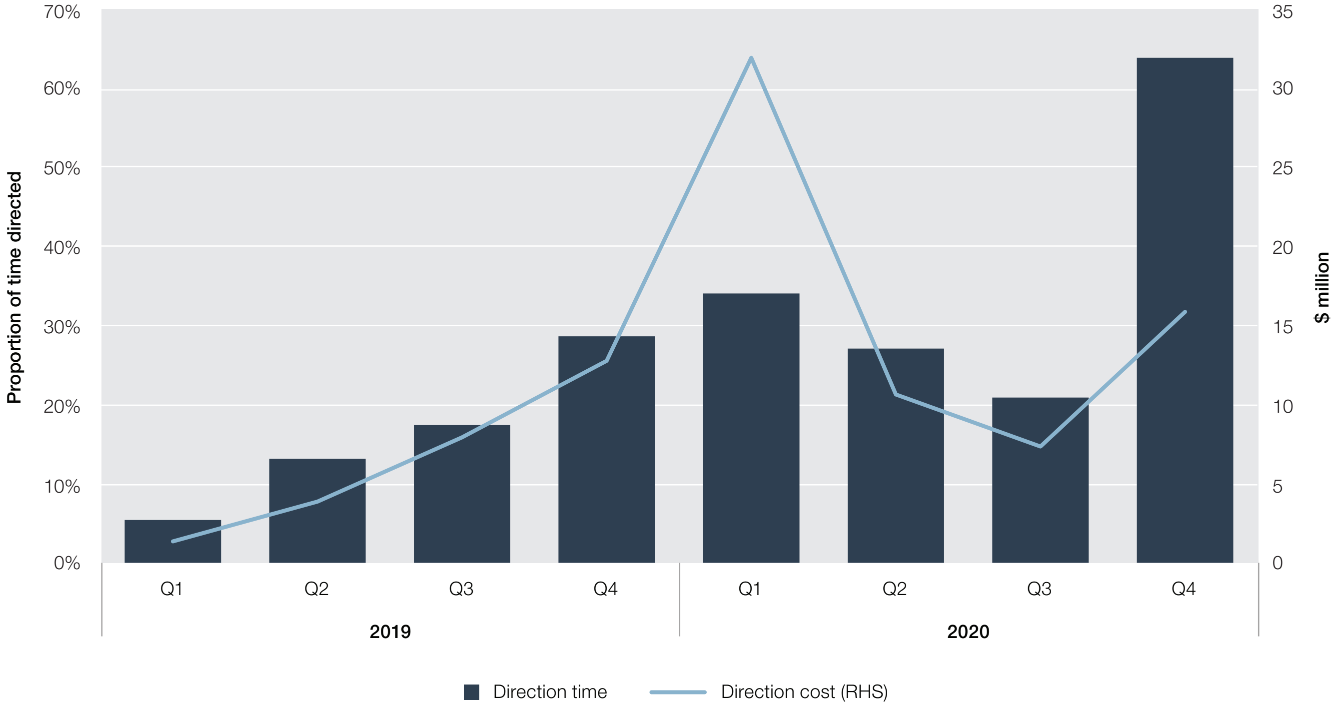
Recent intervention

The use of AEMO directions to manage system security reached a new peak in 2020, when they were in place for more than one-third of the year across the NEM (figure 1.12). Higher than previous use of directions was required in the first quarter to manage 3 separate region separation events.

Late in the year in South Australia, AEMO intervened a record 64% of the time to maintain a minimum level of gas powered generation. This generation was required to provide system strength support at times of low demand.

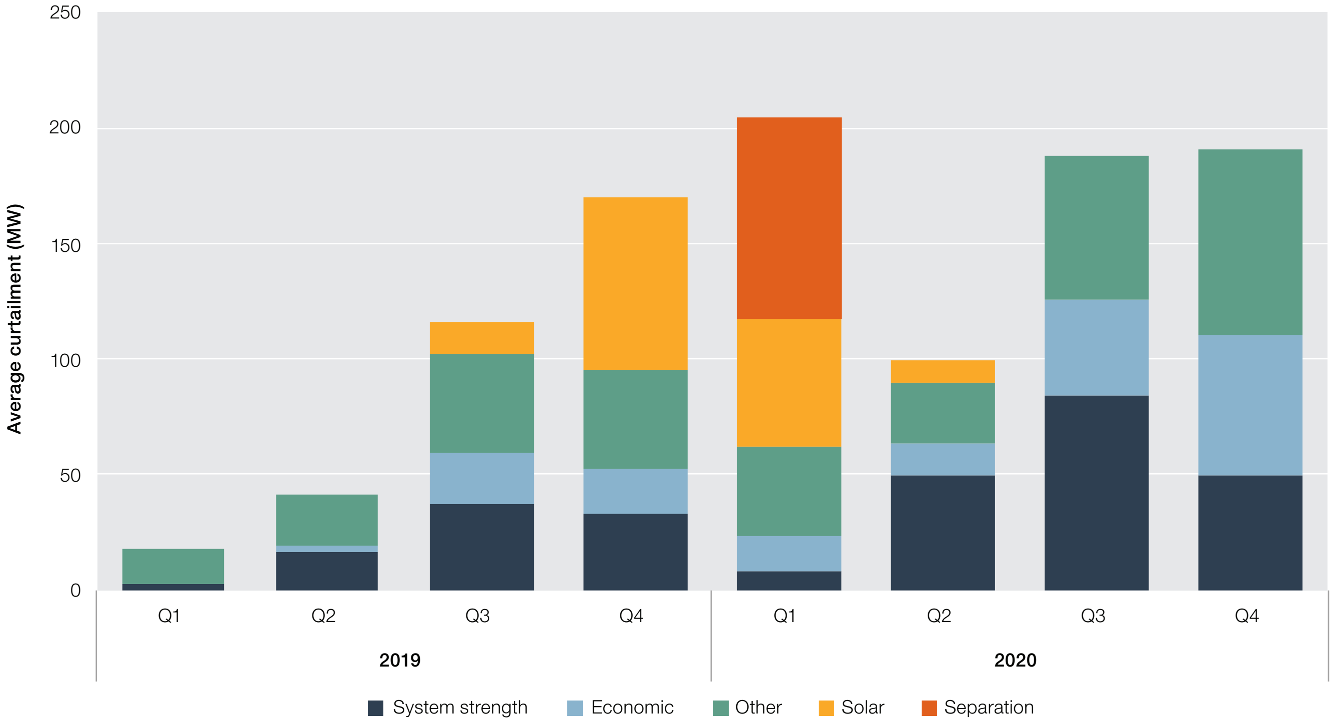
Intervention to curtail renewable generation has risen markedly. Figure 1.13 shows a significant increase in the volume of renewable generation curtailed by system strength constraints over 2019 and continuing throughout 2020. In 2020 there was also an increase in economic curtailment, with renewable generators choosing not to operate at times of negative prices.

Figure 1.12 System security directions



Source: AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Figure 1.13 Curtailment of renewable generation



MW: megawatt.

Source: AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Intervention costs

Generators subject to certain directions from AEMO are entitled to claim compensation. Compensation costs relating to AEMO directions averaged $25 million in 2018 and 2019.[63] Given the scale of these costs, in December 2019 the AEMC limited compensation payments associated with system security directions (and any other intervention to obtain a service for which no relevant market price applies). Despite this change, direction costs rose to almost $66 million in 2020.[64] Around half of this cost was incurred in the first quarter to manage 3 separate region separation events caused by unplanned transmission outages.

Aside from formal compensation, the use of constraints or directions penalises consumers by driving up wholesale electricity prices. For example, by restricting wind or solar output that might have zero marginal costs, AEMO directions may lead to dispatch from synchronous generators with higher costs.

Load shedding

The most extreme form of intervention occurs when AEMO instructs a network business to load shed (that is, temporarily cut power to some customers). This action is rare and only occurs if all other avenues have been exhausted. In recent years, insecure operating states led AEMO to cut supply to some customers in South Australia (December 2016 and February 2017), NSW (February 2017) and Victoria (twice in January 2019).

AEMO also operates schemes that automatically shed generation or load when system frequency exceeds or falls below safe levels. Generation was shed for the first time under South Australia's over-frequency generation shedding scheme in January 2020, when 3 wind farms tripped off following the islanding of the state from the rest of the NEM. In NSW, 20 MW of load at Tumut (NSW) was disconnected in January 2020 when the network was impacted by bushfires.[65]

1.4.3 Spot markets for frequency control services

Some of the services needed to maintain power system stability can be procured through markets. Currently, spot markets exist only for a number of frequency control services. There are currently no market arrangements to procure essential system services such as system strength or inertia.

AEMO also enters long term contracts for:

- network support and control ancillary services, for controlling voltage at different points of the network, controlling power flow on network elements and maintaining transient and oscillatory stability after major power system events
- system restart ancillary services, for restarting the electrical system after a complete or part system blackout.

Frequency control services

AEMO operates markets to procure different types of frequency control ancillary services (FCAS) to maintain stable system frequency. Participants make offers to provide these services in a similar way to how they provide energy offers. AEMO determines which generators will be dispatched to jointly provide energy and FCAS at the lowest cost (known as co-optimisation). The costs are recovered from generators and consumers, partly through a 'causer pays' mechanism.

Eight different FCAS markets operate, each providing a different type of service. *Regulation services* are procured to manage frequency deviations within the normal operating frequency band, while contingency services are procured to arrest any major variations caused by events such as the loss of a generating unit or a significant electricity transmission line. *Contingency services* are available over a range of response speeds (from 6 seconds to 5 minutes). Separate markets operate to raise and lower frequency for each type of service.

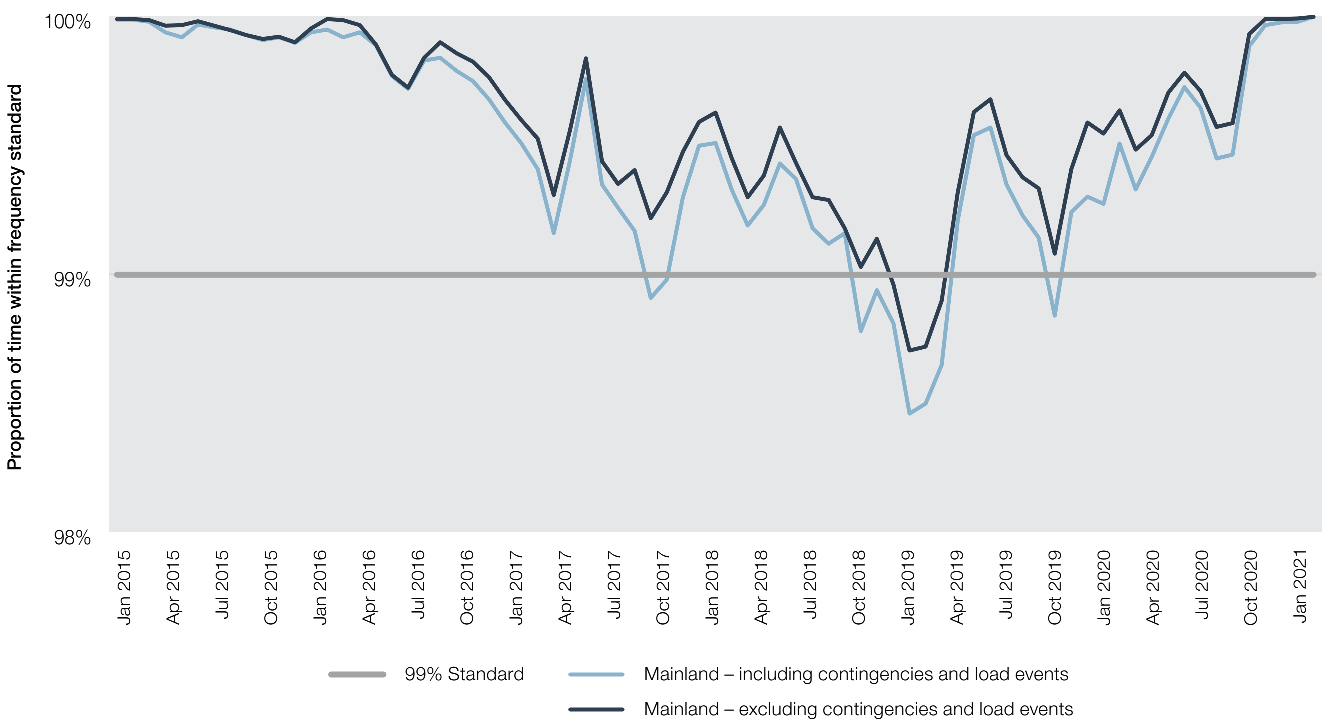
Between 2016 and 2020 the control of power system frequency during normal operation degraded, such that the power system frequency spent more time outside the target frequency of 50 Hz than was historically the case (figure 1.14). Since reforms introduced in 2020, system frequency performance has improved (section 1.4.4).

63 AEMO, *Quarterly energy dynamics Q1 2020*, April 2020.

64 AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

65 AEMO, *Final report – New South Wales and Victoria separation event on 4 January 2020*, September 2020.

Figure 1.14 Proportion of time National Electricity Market mainland frequency is within normal operating band



Note: AEMO calculates daily the percentage of time that frequency remained inside the normal operating frequency band in the preceding 30-day window. Data represents the minimum daily estimate from each month.

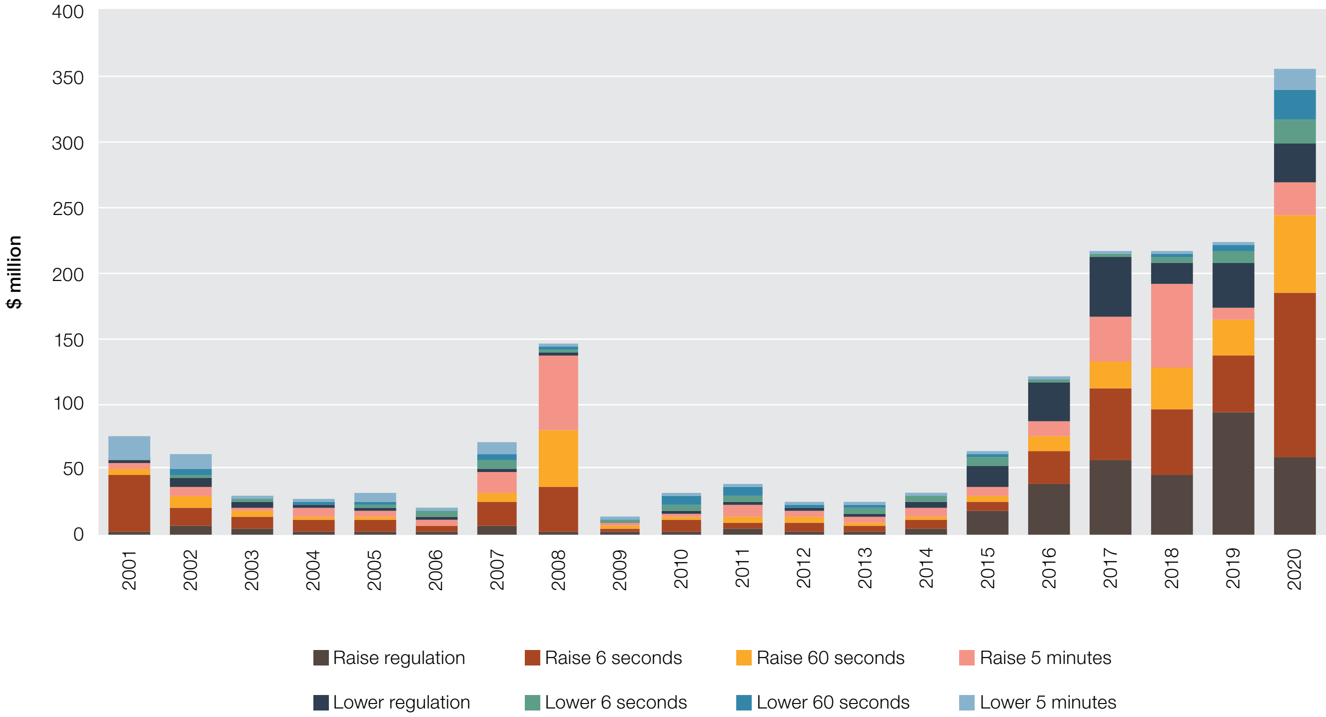
Source: AEMO, *Frequency and time error monitoring – quarter 4 2020*, February 2021.

The degradation in frequency control was reflected in higher FCAS costs. Historically, FCAS costs were low in relation to energy costs. Between 2015 and 2019 FCAS costs rose fourfold to over $220 million (figure 1.15).[66] And in 2020 costs rose further, to over $350 million. FCAS costs for the first quarter of 2020 were higher than they were over the whole of 2019, mainly due to high local costs in South Australia when it was isolated from the rest of the NEM for several weeks. Costs reduced to their lowest level since 2016 for the remainder of 2020 despite an increase in the volume of regulation and contingency services purchased (section 2.10.2).

Reforms in 2017 widened the potential pool of FCAS providers by allowing batteries and demand response aggregators to offer services in those markets. Demand response aggregators now offer FCAS across all NEM regions, VPPs offer services in all mainland regions and batteries offer services in South Australia and Victoria. Some wind farms also offer FCAS. These new technologies and business models will have an increasingly important role in maintaining system security. To strengthen transparency around FCAS markets and encourage participation, the AER publishes quarterly reports on activity in FCAS markets.

66 AER, *Wholesale markets quarterly – Q4 2019*, February 2020.

Figure 1.15 Frequency control ancillary service costs



Source: AER.

1.4.4 Addressing gaps in frequency control services

While spot markets operate for 8 types of FCAS service in the NEM, gaps have emerged in recent years, both in system normal conditions and in circumstances where a very fast response is needed. Reforms are being implemented to address these gaps.

Mandatory frequency response

The power system increasingly needs fast-response frequency services to manage volatile changes in frequency caused by shifts in weather-dependant generation.

Reforms introduced in 2020 require all capable generators and batteries to provide primary frequency response support by responding automatically to small changes in power system frequency, either in the form of a change in generation or a demand response.

In effect, generators must be engineered to vary from their preferred energy dispatch whenever frequency goes outside a specified range. The aim is to ensure an immediate response is available to address an imbalance so that FCAS markets have enough time to deliver frequency services.

The rule commenced in June 2020 as an interim arrangement that will expire in June 2023. During the fourth quarter of 2020, a high proportion of thermal generators changed unit settings, bringing improved frequency performance. There was also a decline in the proportion of regulated FCAS sourced from coal fired generators (from 7% in the third quarter of 2020 to 3% in the fourth quarter of 2020), with corresponding increases in wind and solar farms' share of these costs. Additionally, some generating units registered to provide FCAS services for the first time.[67]

The AEMC is considering a longer term solution (called primary frequency response) that would offer payments to encourage participants such as large batteries to respond to small frequency changes during the market's normal operation. The AEMC expects to publish a draft proposal by September 2021.

In 2021 the AEMC was also considering a proposal from AEMO to enhance incentives for market participants to offer primary frequency response services during normal conditions. A draft determination is scheduled for September 2021.

67 AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Very fast frequency response

The AEMC made a draft rule in April 2021 to introduce a payment mechanism to incentivise and reward businesses such as utility scale batteries to provide very fast frequency response. The reform addresses a gap in current arrangements, whereby frequency services can take up to 6 seconds to come online. But the rising incidence of frequency deviations caused by sudden shifts in renewable generation sometimes requires a faster response. Providers of the new service must be able to deliver it within 2 seconds. It can also be provided by inverter-based technologies such as wind, solar PV, batteries and demand response.

To allow participants to adjust to the new rule, its implementation will be delayed to start 3 years after the AEMC's final decision (due July 2021).[68]

1.4.5 Addressing gaps in system strength and inertia

Ensuring the availability of essential system services (frequency response, operating reserves, inertia and system strength) is a pivotal element of the ESB's NEM 2025 reforms.

There are currently no market arrangements to procure system strength or inertia in the NEM. In the past, these properties were so plentiful that no value was ever placed on them and no mechanism to procure or schedule them was required. Despite emerging gaps in inertia and system strength, market solutions have not evolved for their provision.

Inertia is a system-wide property than can, to some extent, be shared across regions. It becomes a local issue only if a region is islanded from the rest of the market. Because of this, the ESB's preferred long-term approach is to develop a real-time spot market for inertia, with structured procurement as an interim solution.

By contrast, system strength is a relatively localised phenomenon, and a shortage requires local solutions. The ESB notes that the localised nature of system strength makes it currently unsuitable to a spot market, but it is scoping options for a market solution to supply inertia in the longer term.

Until recently, gaps in system strength and inertia were addressed purely through market intervention by AEMO. In particular, AEMO has used its directions power to direct synchronous (usually gas) plant to operate to raise inertia and system strength and/or constrain off weather-dependant generation that is draining strength from the system.

Reforms in 2017 in South Australia and in July 2018 elsewhere introduced a new approach requiring generators and transmission networks to play an active role in managing system strength.[69] In particular, if AEMO identifies a system strength shortfall in a region:

- transmission network businesses must maintain minimum levels of system strength for generators connected to the network
- new connecting generators must 'do no harm' to the level of system strength needed to maintain the security of the power system. This rule applies to all new connecting generators in the NEM. In effect, new plant must be able to operate to specific system strength levels before it can connect to the system.

Similar requirements were imposed on transmission businesses to maintain minimum levels of inertia (or provide alternative services to meet these levels) if a shortfall is identified.

68 AEMC, *National electricity amendment (fast frequency response market ancillary service) rule, draft rule determination (Infigen energy)*, April 2021.

69 AEMC, *Managing power system fault levels*, information sheet, September 2017.

In April 2021 the AEMC found current arrangements for managing system strength (the 'do no harm' rule and obligations on transmission networks) to be ineffective and cause inefficient delays in connecting new generators. It announced draft reforms to make it simpler, faster and more predictable for new generation – renewables in particular - to connect to the grid.[70] The reforms:

- require transmission networks, working with AEMO, to provide system strength when and where it is needed. The network would consider options for providing system strength, such as building network assets, contracting with existing synchronous generators, retuning existing generators and other solutions. Identified solutions would then be assessed for market benefit through the regulatory investment test (RIT-T) (section 3.12.6). The AER would assess the efficient cost of providing system strength services through its periodic reviews of each network's revenue requirements
- introduce new access standards for generators connecting to the grid to ensure they only use efficient amounts of system strength
- introduce a new charging mechanism for system strength so that those parties who use the service pay for it. New generators would have the choice of paying the network for the system strength it provides or creating their own system strength. The AER would set charges through published guidelines on pricing methods.

The AEMC's development of these rule changes has been informed by the ESB's work and direction through the NEM 2025 project. The draft reforms are consistent with the ESB's preferred approach of 'structured procurement'[71] of system strength.

In 2021 the AEMC was separately considering the launch of scheduling and deployment mechanisms for system strength, including consideration of a short term market for these services to complement structured procurement.[72]

New services

Market bodies are exploring the potential need for a fast-responding ramping service in the NEM to manage variability and uncertainty as the NEM progresses towards very high shares of weather-dependent supply. In particular, the market is facing a growing need to ramp (adjust) quickly to sudden changes in wind and solar generation.

Beyond this, market bodies are considering the introduction of a new service for operating reserve provision. To date, operating reserves have been provided by AEMO's dispatch process keeping 'headroom' on operating generators.

In January 2021 the AEMC concluded that a new operating reserve service may be needed to address changes in net demand that were not forecast and therefore unexpected by market participants.[73] It expects to release a draft determination later in 2021. The ESB is working closely with the AEMC on this matter as part of its NEM 2025 project.

The project is considering the need to explicitly value operating reserves to encourage resources with capability to ramp up or down quickly and provide flexibility to the grid. It is also considering a price signal for reserves that would reflect their real value at any point in time.

While these reforms to security service provision focus on the supply side, reforms progressing on the demand side may also ease the pressures causing security issues. A new demand response market, commencing in October 2021, will allow participants to offer demand reductions through AEMO's central dispatch process, and be paid for any capacity called on (section 1.3.3).

70 AEMC, *National electricity amendment (efficient management of system strength on the power system) rule 2021*, draft rule determination, proponent: TransGrid, 29 April 2021.

71 'Structured procurement' involves AEMO sourcing a resource outside spot markets. It is currently used for the RERT mechanism and voltage control; and for minimum levels of system strength and inertia.

72 AEMC, *National electricity amendment (efficient management of system strength on the power system) rule 2021, draft rule determination, proponent: TransGrid*, 29 April 2021.

73 AEMC, *Reserve services in the National Electricity Market*, directions paper, proponents: Infigen Energy, Delta Electricity, January 2021.

Box 1.5 System strength and inertia issues across the National Electricity Market

South Australia has been the epicentre of inertia and system strength issues in the National Electricity Market (NEM) for a number of years. More recently issues have emerged in Victoria, Queensland and Tasmania.

South Australia

The Australian Energy Market Operator (AEMO) declared a system strength gap in South Australia in October 2017 and an inertia shortfall in December 2018. The issues intensified following the closure of a major coal fired power station in 2016 and a rapid escalation in grid scale wind and solar generation. The problem is acute when low to moderate demand combines with high levels of renewable generation to cause low spot electricity prices. When prices are too low for gas powered generators to cover their short run costs, the generators bid high to avoid dispatch. With fewer synchronous generators operating, inertia levels and system strength levels fall.

South Australia's transmission business ElectraNet, which must address the issues, is installing 4 high inertia synchronous condensers to cover the system strength and inertia gaps. ElectraNet expects all the devices to be in place by 2021.

In 2020 total costs for directing South Australian generators for system strength reached $49 million (or $4 per megawatt hour (MWh)) – almost double those costs in 2019.[74] In the first quarter of 2021 AEMO directed gas powered generators to be online 70% of the time. With low spot electricity prices prevailing for much of the summer, it was uneconomic for gas powered generators to operate in these periods. Around 30% of all gas powered generation in the state was made under direction during the quarter.[75]

In August 2020 AEMO declared a new inertia shortfall in South Australia following the islanding of South Australia earlier in the year, in anticipation of continued growth in rooftop PV and declining minimum daytime demand. ElectraNet is procuring fast frequency response to meet the shortfall.

Victoria

In late 2019 system strength issues emerged in north west Victoria and south west NSW, where a large number of solar farms were being commissioned over a short period, causing system strength and voltage issues. In December 2019 AEMO declared a system strength shortfall in north west Victoria. The area is too remote from synchronous generators for AEMO to manage the issue through directions to gas or coal fired generators. Instead, AEMO intervened by constraining the output of 5 solar farms (4 in Victoria and 1 in NSW) by 50% of their maximum output. The constraints equated to a loss of up to 170 megawatts (MW) of output. The intervention aimed to manage the risk of voltage instability following a contingency such as the loss of a nearby transmission line.

Following changes to inverter settings for the affected plants, AEMO lifted the constraints in April 2020. AEMO (as the network planner for Victoria) also assessed combinations of synchronous condensers to supply additional system strength. As a longer term strategy, AEMO conducted a cost–benefit analysis of building new transmission capacity to unlock renewable capacity in the region. It estimated a lead time for this investment of 6 to 7 years.

In 2020 AEMO, on behalf of the Victorian Government, procured 250 MW from Neoen's 300 MW battery to increase the capability of the Victoria to New South Wales Interconnector and respond to unexpected network outages in Victoria from November 2021. AEMO procured sufficient resources to meet system strength requirements until August 2022. It is assessing the need for further intervention beyond that time.

74 AEMO, *Quarterly energy dynamics, Q4 2020*, February 2021.

75 AEMO, *Quarterly energy dynamics, Q1 2021*, April 2021.

Queensland

In April 2020 AEMO announced a system strength shortfall in northern Queensland. The issue occurs when insufficient coal or hydro plant is operating. It introduced new constraints preventing 3 renewable generators in the region from operating when coal and hydro output falls below a set threshold. As an interim solution, the transmission provider Powerlink entered into an agreement with CleanCo Queensland to provide system strength services using CleanCo assets in Far North Queensland. Powerlink is required to provide a longer term solution by August 2021.[76]

Changed inverter settings at wind and solar farms in the north of the state, as well as increased demand, resulted in system strength curtailment falling to near zero in the first quarter of 2021.

Also in 2020 Powerlink committed to install a synchronous condenser for which the costs would be recovered from committed and future connecting renewable generators. This was a first for the 'system strength as a service' model for new connecting generators.[77]

Tasmania

In 2019 AEMO declared inertia and system strength shortfalls in Tasmania over the period 2020 to 2025. In response, the transmission network (TasNetworks) procured services to meet the shortfalls by contracting with existing synchronous machines and through delivery of new operating procedures and processes.

Also in Tasmania, hydro generation units were directed to be online for system strength for the first time since NEM start due to a temporary shortfall in late 2020 following a transmission outage.[78]

1.5 Efficient integration of distributed energy resources

Over the past decade, many customers have sought to reduce their energy costs, and support renewable energy, by investing in DER – for example, rooftop solar PV systems, household battery systems and demand response such as home energy management systems – at their household or business. The CSIRO and Energy Networks Australia estimated household bills could lower by as much as $400 per year if these resources are optimised.[79]

When integrated efficiently, DER offers flexibility that can help delay the need for large scale generation and network investments and can provide new sources of network support and energy management capabilities. According to estimates published by AEMO and developed by Energy Synapse, in 2020 the NEM had around 4.3 GW of potential demand flexibility. When small scale solar PV and battery capacity is added, the pool expands to around 15 GW and is forecast to reach up to 21 GW by 2022.[80]

Reforms introduced in 2017 aimed to tap into this pool by allowing batteries and demand response aggregators to offer services in FCAS markets (section 1.5.3). Technologies such as virtual power plants are increasing opportunities for smaller scale DER to participate in FCAS markets and potentially the wholesale market through demand response and emerging markets such as voltage control and ramping. Pilot programs are exploring a new market design for a 2-way energy system and marketplace in which DER can participate via aggregators to provide wholesale energy and/or ancillary services to the electricity grid and market.

But the ability of DER to benefit customers and support the power system depends on how well those resources interact with the system. The growth in DER is making electricity demand more volatile due to variations in controllability (changes in weather conditions can be sudden and frequent) and levels of performance. Additionally, limited visibility over the scale and distribution of DER resources makes it difficult to anticipate and manage issues when they arise. These issues are leading to more curtailment of those resources because of network congestion and insufficient services like frequency control system strength, voltage control and ramping. The ESB reported that, without further action, the maximum instantaneous penetration of renewable resources could be limited to 50–60%.[81]

76 AEMO, *2020 system strength and inertia report*, December 2020.

77 ESB, *Health of the National Electricity Market 2020*, 2021, p 31.

78 AEMO, *Quarterly energy dynamics, Q4 2020*, February 2021.

79 CSIRO/ENA, *Electricity network transformation roadmap, Final report*, April 2017.

80 Cited in ESB, *Health of the National Electricity Market 2020*, 2021, p 74.

81 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 16.

On the customer side, it remains difficult for small consumers to access markets to deliver energy or system services that could reward them for shifting their demand over the course of a day or several days.

The ESB considers that current market arrangements, along with those for metering and connection, do not adequately support consumers wanting to participate in the market and are complex to navigate. Today, people can contract with one retailer only and not with other intermediaries (such as aggregators) in the energy market. Furthermore, retailers are limited in what they are permitted to offer to customers. The ESB aims to reduce barriers to participation in the market so that consumer benefits can be unlocked without the need for consumers to engage in the market more than they do currently. The ESB and market bodies have been carrying out research on this and are also working with ARENA to commission studies to better understand the potential for flexible demand under a range of scenarios and conditions.[82]

1.5.1 Distributed energy resources and distribution network security

Distribution networks were historically engineered to transport electricity one way – that is, from large generators to energy customers. But, with the continued uptake of rooftop solar PV systems and other types of DER, the networks now increasingly support multi-directional energy flows. Customers can generate electricity, store it and export it to their local distribution network.

While grid scale wind and solar generation raise security issues for transmission networks, distribution networks face similar issues as consumers adopt DER and export electricity into the grid. Some networks are experiencing congestion as areas of their networks reach capacity limits on the amount of DER that they can host. Congestion tends to manifest through voltage issues where electrical pressure reaches its upper threshold as more and more rooftop solar PV units inject power into the grid.

In 2020 AEMO published a survey on how DER are impacting distribution networks in the NEM, illustrating the range and complexity of these issues.[83] Distribution businesses identified voltage issues; problems with inverter settings at customers' premises; and phase balancing and thermal capacity issues on feeders and at substations. The issues vary by the size and location of PV clusters in each network, relative to physical network characteristics and load. AEMO's survey findings confirmed South Australia and Queensland experience the most significant challenges due to their high uptake of solar PV systems, exacerbated by some cluster areas in these states having generally weaker network capacity.

The performance of some inverters connecting DER devices to the network has posed challenges. AEMO estimated around 15% of rooftop systems in Queensland and 30% in South Australia did not meet the Australian standard for inverters to ride through faults.

In February 2021 the AEMC introduced minimum technical standards for DER, including rooftop solar PV inverters, on their ability to ride through short-duration under-voltage disturbances.[84] This is a priority in South Australia following recent power system events linked to the tripping of solar PV systems.

1.5.2 Static and flexible export limits

As solar penetration increases to levels that cause network constraints, distributors have the option of expanding the network and recovering the costs from all consumers through higher charges. But network augmentation is costly. Some consumer groups argue the approach is also inequitable, with the cost of DER integration being borne by all consumers regardless of whether they own DER.[85] Nevertheless, customer research conducted by AusNet Services found support for some investment to allow solar exports, with the cost to be shared among all customers and with government.[86]

82 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 57.

83 AEMO, *Renewable integration study, Stage 1*, Appendix A, April 2020.

84 AEMC, *National Electricity Amendment (Technical Standards for Distributed Energy Resources) Rule 2021, determination, proponent: AEMO*, February 2021.

85 AEMC, *Economic regulatory framework review, integrating distributed energy resources for the grid of the future*, September 2019.

86 AusNet Services, *2021–2025 electricity distribution price review, customer forum final engagement report*, 2020, p 14.

An immediate challenge is the rising instances of distribution networks applying static export limits that restrict DER exports in constrained parts of their network. While these measures help balance the system, outcomes are not efficient for customers – in particular, DER owners. Some customers in areas with high levels of solar penetration are facing very low or zero export limits. In Victoria, several thousand customers have been constrained to zero exports across 4 of the 5 distributors.[87] South Australia may need to introduce reduced or zero export limits in parts of Adelaide's southern suburbs.[88]

Flexible export limits offer a better solution than applying a static export limit to all consumers (as occurs now). Flexible export limits are based on the premise that technical issues caused by DER exports to the grid occur infrequently, so blanket restrictions are unnecessary for most of the time they are imposed.

Distributors with a high level of DER penetration are already shifting towards flexible export limits. SA Power Networks will offer new solar customers the option to export up to 10 kW from their solar panels but agree to be constrained as required to maintain system security; or have a fixed export limit of 1.5 kW.[89] The option will be offered to new or upgrading solar customers in some congested areas from mid-2021.

For most of the time, customers choosing the flexible option would have the opportunity to export more than they would on a lower fixed export limit, even in highly overloaded parts of the network. Export limits will only be lowered periodically when necessary to avoid overloading the network and to help maintain a reliable electricity supply.

More broadly, AEMO has the power to direct a full or partial reduction in output from solar systems in South Australia during electricity security emergencies. All solar installations in South Australia since September 2020 are required to have flexible export limit capability. This power was used for the first time in March 2021 to switch off around 12,000 solar systems at a time of near-record minimum demand. These powers are being considered for other NEM regions due to the continued rapid uptake of rooftop solar PV. AEMO is also working with electricity distributors to establish real-time visibility requirements for distributed solar PV systems available for curtailment, and consistent real-time visibility for all new commercial scale systems.

1.5.3 Pricing of solar exports to the grid

Pricing reform has become another focus to manage distribution network congestion caused by rooftop solar PV. At present, distribution networks earn revenue by charging for the use of poles and wires to transport electricity *from* the grid *to* the consumer. At present, distribution networks cannot charge solar PV owners for exporting electricity back into the network, beyond a basic charge to connect to the network. In effect, exporting solar output into the grid is treated as a 'free' service provided by the network that is paid for by all consumers through higher energy bills.

The AEMC concluded a 'use of system charge' for DER exports is part of an efficient solution to optimise the benefits of DER, while managing the risks and costs of congestion at times of oversupply from small scale (solar PV) generation. Under draft reforms made in March 2021, distribution network services will in future be regulated as 2-way services and be able to charge to transport electricity both from the grid and into it.

The draft reforms are not mandatory. Networks will be allowed to develop flexible pricing that allocates costs in a more equitable and efficient way, accounting for their capability, customer preferences and jurisdictional policies. The aim is to reward customers for actions that better use the network or improve its operations. For example, a customer could choose a level of 'firmness' that rewards them for reducing their exports to the grid at times when there is limited network capacity.

The AEMC found that, if networks introduce export charges, around 80% of customers (those without solar systems) would see their bills drop because they would no longer pay for solar export services they were not using.

For the 20% of customers with solar, export charges would reduce their earnings from solar exports. A 4–6 kW system, for example, would still earn on average $900 – about $70 less than now. Even without export charges, solar owners would face a similar drop in earnings if they are constrained from exporting energy just 10% of the time.[90]

87 Clay Lucas, 'Power failure: homes hit by solar limits as distributors protect network, and profits', *The Age*, 14 March 2021. Estimates are based on information provided by Victorian distributors.

88 SA Power Networks, 'Working with industry to boost customer solar options' [media release], 14 April 2021.

89 SA Power Networks, 'Working with industry to boost customer solar options' [media release], 14 April 2021.

90 AEMC, *National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule, draft rule determination*, March 2021.

The reforms would also introduce incentives for distribution networks to deliver export services that customers value. The AER would be required to review the scope of its service target performance incentive scheme (STPIS) to reward or penalise networks for the quality of their export service provision, and to develop a method to calculate customer export curtailment values to help guide efficient network expenditure. These values aim to measure the detriment to customers and the market from having exports curtailed (and so provide a guide to the pricing of DER exports that might avoid this scenario).

To support the transitional introduction of export tariffs the AEMC modified revenue recovery arrangements to allow distributors to trial alternative tariff structures.

1.5.4 Visibility of distributed energy resources

As we move towards a system of millions of DER, issues arise from DER's inherent lack of visibility, which compromises the market operator's ability to understand DER behaviour, forecast electricity demand, schedule dispatch and manage power system security. In particular, the market operator and distribution networks have little real-time visibility of PV systems less than 5 MW, including rooftop solar.

In response to these issues:

- arrangements announced in September 2018 require AEMO to establish a register of DER in the NEM. The register gives network businesses and AEMO visibility of where DER are connected to help plan and operate the power system as it transforms
- demand response and VPP trials are exploring how DER behaves during disturbances and developing a database of DER installations
- new technical standards for DER finalised in 2021 aim to improve DER performance to support energy system security
- the ESB is looking at ways to improve DER visibility over the longer term to support efficient forecasting and scheduling through its NEM 2025 project.

1.5.5 Distribution network pricing

While pricing of DER exports into the grid is a major reform focus in 2021, longer term reforms to retail energy prices also impact DER and its efficient use. Most retail customers are still on some form of fixed retail tariff that takes little account of how their energy use affects the network. Market bodies have been progressing a shift towards cost-reflective tariffs that more closely account for how a customer's energy consumption pattern affects the network. Cost-reflective network tariffs should be structured to fall at times of low demand (when the network has spare capacity) and rise at times of peak demand when the networks are under strain.

Reforms introduced in 2017 require electricity distributors to progressively shift retailers, aggregators and other third-party providers onto network tariffs that more closely reflect the true costs of their customers' use of the distribution network. The reform operates by requiring networks to levy the new tariffs on *their* customers (mainly energy retailers) but leaves it open to retailers to decide how to pass on the changes to their residential and business customers.

Retailers may offer different price arrangements to suit different customer preferences. Some customers may prefer traditional pricing with a single price for energy regardless of when it is used. But, for customers with some flexibility in their energy use, retailers can offer incentives to switch their energy use to times of low demand and operate DER such as rooftop solar PV systems and batteries in ways that minimise network stress.

The AEMC found that, despite progress at the network level, cost-reflective tariff reform at the consumer level has proven to be difficult to implement. The AEMC cited a lack of analysis of the impact on various consumer groups, including a lack of clarity about how network tariffs could play out through retailers, how retailers will translate tariffs to customers and what protections and supports will be put in place for vulnerable consumers, as factors contributing to slow progress.[91] Survey responses from members of an AEMC technical working group rated 'retailer support and the extent of pass through into retail tariffs' as the largest cause of delay to the pace of tariff reform.[92] Retailer feedback to the AER suggests retailers are still working on developing more innovative offers.

91 AEMC, *Electricity network economic regulatory framework 2020 review*, final report, 1 October 2020, p 45.

92 farrierswier, *Effectiveness of the TSS process and options for implementing export charges*, March 2021.

The limited penetration of smart meters for residential and small business customers is one factor limiting the uptake of cost-reflective tariffs. Smart meters (or manually read interval meters) measure customers' electricity use across the day. At February 2021 around 39% of customers in the NEM had metering capable of supporting cost-reflective tariffs. But installation rates vary across regions. Around 98% of Victorian customers had access to a smart meter. NSW had the next highest penetration of smart or interval meters at around 25% of customers. Installation levels in other regions ranged from 15% of customers in Queensland to 23% of customers in the ACT.[93]

Even accounting for the ongoing rollout of smart meters, uptake of cost-reflective tariffs has been slow. Less than 23% of customers outside of Victoria with advanced meters have cost-reflective network tariffs. Tasmania and NSW have seen the greatest take-up of these tariffs (at 46% and 39% of customers respectively), with much lower rates in Queensland (1% of customers), South Australia (6% of customers) and the ACT (4% of customers).[94]

South Australian and Queensland distributors proposed to shift all customers with smart meters onto cost-reflective network pricing from 1 July 2021. The proposed shift would significantly step up the progress of tariff reform in those states.

1.5.6 Demand management incentives

The AER supports distributors to implement strategies to manage the impact of DER on their networks through a demand management incentive scheme and demand management innovation allowance (section 3.12.9). Among projects recently supported through the scheme are large and small scale storage projects, microgrids and load control projects. The scheme has also funded research on subjects including future grid and EV demand; and studies on the use of energy trading and distributed energy platforms.

1.5.7 A 2-sided market

The efficient integration of DER into the power system is a priority reform in the ESB's NEM 2025 project. The focus is to enable the integration of DER such as rooftop solar and distributed storage into the system so they can provide services to networks, the wholesale market and other consumers. A key element is to appropriately value flexible demand to incentivise the owners of distributed resources to respond to price signals on the system's need for them.

Alongside reforms already being progressed by the AEMC, the ESB is focused on rewarding customers for building flexibility into their energy use. To provide these opportunities to customers, it needs to be made easier for innovative new retailers and service providers to enter the market and offer different choices to customers.

In 2021 the ESB is exploring options for the NEM to operate in the longer term as a 2-sided market in which traditional participant categories such as retailers, generators and aggregators would be replaced by 2 categories – those who use electricity and those who sell it on behalf of end users. This would make it easier for new types of traders to enter the market. It could also mean that single end users could be their own trader for some services – and use other traders to buy or provide other services for them.[95]

A 2-sided market has all its participants responding to price signals and being exposed to market outcomes. Energy customers could use metering and other evolving technologies to set up arrangements for how they wish to participate, either through a retailer or aggregator.

The AEMC is taking steps toward making these reforms operable through its review of integrating energy storage systems into the NEM. The AEMC aims to release a draft decision in July 2021.[96]

The ESB is also considering the introduction of flexible trading arrangements, including a new participant category called 'scheduled lite', so that those resources that do not normally participate in the market can offer services such as demand response.[97]

93 Estimates derived from AER market intelligence.

94 AER, *Retail energy market performance update for Quarter 2, 2020–21*, April 2021.

95 ESB, *Moving to a two-sided market*, April 2020.

96 AEMC, 'Integrating energy storage – new date for draft National Electricity Rules changes' [media release], 29 April 2021.

97 ESB, *Post 2025 Market Design Options – a paper for consultation*, April 2021, p 71.

1.6 Efficient investment and access

Aside from reliability and security challenges, Australia's energy market transition poses risks to efficient investment in, and use of, energy infrastructure. The market lacks a coordinated framework to locate generators efficiently and provide transmission capacity where it is needed.

Transmission network providers are receiving an unprecedented number of connection enquiries from renewable projects seeking to locate in sunny or windy locations on the edges of the grid, where transmission capacity is weak. Connecting new plant in these areas can cause network congestion, which weakens system security for the grid as a whole. Congestion can prevent generators in an affected area from being dispatched efficiently.

A lack of transparency intensifies the problem. While significant information is available about a generator once it connects to the grid, projects have limited transparency before the generator signs a connection agreement with a network. Progress has been made in this area. New rules effective from December 2019 require network businesses to share connection information about generation proposals with AEMO, which then publishes this information. The rules provide developers with up-to-date information about generation projects in the pipeline to help guide investment decisions on where to locate new generators and to assess project viability.[98]

Reforms introduced in 2018 apply stricter technical standards to connecting generators to help mitigate the risks of new plant causing congestion (section 1.4.5).[99] Transmission networks may impose such technical requirements (generator performance standards) as they see fit. But, as networks become more constrained in areas with high quality renewable energy resources, requirements placed on connecting generators are becoming increasingly stringent. Many project proponents find grid connection (access) difficult to negotiate. The arrangements have raised concerns among developers, with some reporting that network businesses are delaying the processing of connection applications or altering required standards during negotiations.

Current access frameworks also fail to address perverse outcomes that can occur. For example:

- multiple generators seeking to connect to a network may each invest in separate connection assets when a shared asset may be more efficient. In 2021 the AEMC has been consulting on draft reforms to enable a generator, or a group of generators, to fund shared network assets and have those assets subject to a special access regime.[100] Development of REZs will also address this issue (section 1.6.1)
- a new connecting generator is not penalised for causing network congestion that degrades the quality of access for other generators. Existing generators cannot gain firm network access to avoid this risk.

These issues are difficult to address without pricing reforms. Current frameworks do not provide accurate signals to new generators on the costs and risks of connecting to weaker parts of the grid. Generators connecting to the grid do not pay for their use of the transmission networks, beyond a basic charge to connect to the nearest point on the network. The cost of other work needed to augment the network to accommodate a new generator with a poor network connection is charged to all energy users. Further, current frameworks do not allocate congestion costs among generators.

In 2021 the ESB assessed that, without reforming access arrangements, new generation will locate and operate in ways that exacerbate congestion, reducing efficiency and raising costs for consumers. Alongside piecemeal reforms to the market's architecture, 2 major reform strands aim to make access to transmission networks more efficient. The immediate focus is on coordinated generation and transmission planning. A longer term focus is on pricing reforms and congestion management tools.

98 AEMC, *Transparency of new projects*, fact sheet, December 2019.

99 AEMC, *Generator technical performance standards rule determination*, information sheet, September 2018.

100 AEMC, *National electricity amendment (connection to dedicated connection assets), draft rule determination, proponent: AEMO*, November 2020.

1.6.1 Coordinating generation and transmission investment

Transmission investment tends to lag behind generation investment, often resulting in delays between the completion of a generation project and the network being ready for the plant to connect. These lags create uncertainty for generation proponents and may delay efficient investment.

The lag in transmission investments is driven by 2 underlying factors:

- The business case for transmission upgrades typically requires evidence of a current, rather than a likely future, market need.
- Approval of transmission projects requires a thorough cost-benefit assessment to ensure customers are getting value for money.

The Victorian Government, concerned that the national framework on transmission approvals excessively delays the delivery of projects and fails to account for the full benefits of investments, introduced new rules in February 2020 that allow priority projects such as grid scale batteries and transmission upgrades to be fast-tracked.

Reforms are progressing to better coordinate planning and investment in transmission and generation to ensure new assets are built in the right place, at the right time, to serve the long term interests of consumers. More coordinated planning will facilitate efficient grid connection and reduce the risk of congestion scaling back generator earnings. Reforms also focus on streamlining the approval process for large transmission projects.

Integrated system planning

The centrepiece of reform to coordinate investment in transmission and generation to serve the long term interests of consumers is AEMO's Integrated System Plan (ISP). The plan (first published in 2018 and updated in 2020) provides information to the market on future generation and network requirements over a 20-year horizon. It is a whole-of-system plan that aims to facilitate strategic transmission investments and deliver the least cost mix of resources to supply secure and reliable energy to consumers.

The ISP forecasts where and when network investment is likely to be needed to accommodate the large amount of new generation likely to connect to the grid in coming years. Elements include upgrading transmission interconnection where needed for efficient sharing of energy, upgrading storage and backup supply across regions.

Renewable energy zones

A key initiative is to cluster new wind and solar projects in hubs called *renewable energy zones* (REZs) so that efficient transmission investment can be made to transport energy to customers. The clustering of renewable plant reduces the amount of transmission investment that would be needed if new renewable plant were widely dispersed. In 2020 AEMO highlighted 35 possible REZs across eastern Australia.

State governments have initiated programs to support the development of REZs identified through the ISP – NSW is developing 5 REZs, Victoria is consulting on 6 proposed REZs, and Queensland has identified 3 REZ corridors (figure 1.16). The ESB prioritised the development of REZ arrangements as a first step in improving transmission access and is working with state governments to efficiently plan, develop and maintain REZs to manage congestion and other risks.[101]

The NSW Government's Electricity Infrastructure Roadmap, launched in November 2020, will underwrite 12 GW of renewable energy across 5 REZs (Central-West Orana, New England, South West, Hunter, Illawarra), support the development of transmission assets and set a pathway for 2 GW of long-duration energy storage (and potentially other firming capacity) by 2030. The development of these assets is intended to be sized and timed to replace capacity lost through the progressive closure of coal fired power stations.

In February 2021 the Victorian Government released a plan to develop 6 REZs across the state, to add 10 GW of new renewable energy. The government will establish a new body – VicGrid – to plan and develop the zones and has allocated $540 million to invest in network infrastructure.[102]

In May 2021 the Queensland Government committed $145 million to establish 3 REZs – the Northern, Central and Southern QREZ. The government will undertake strategic network investments, streamline development of renewable energy projects and facilitate industrial energy demand to capitalise on available renewable energy resources.

101 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, pp 79–80.

102 DELWP, *Victorian renewable energy zones development plan*, directions paper, February 2021.

Transmission investment

The 2020 ISP identified 18 transmissions augmentations to accommodate weather-dependant generation and DER and the phasing out of coal generation. The projects fall into 4 categories:

- *Committed* projects, which are those already approved and underway. They include:
  - the installation of synchronous condensers in South Australia to address inertia and system strength issues (scheduled for completion in 2021)
  - transmission upgrades in western Victoria to unlock capacity from new solar farms in the area (on track to be commissioned in 2 stages, by 2021 and 2025)
  - a minor upgrade to the Queensland–NSW interconnector scheduled for 2021–22. The AER in 2020 fast-tracked its regulatory test assessment on the upgrade, which aims to provide additional import capacity into NSW to supplement local supply following the closure of Liddell power station. The AER determined that the upgrade, estimated at $218 million, will deliver a net economic benefit to Australian energy consumers
- *Actionable* ISP projects, which are those considered by AEMO as critical for immediate development but still undergoing regulatory approvals. The projects, forecast to cost between $6.8 and $12.7 billion over the period 2022–32, include:
  - Project EnergyConnect – a new interconnector linking South Australia and NSW aimed at unlocking stranded renewable investments, for expected completion by 2024–25. TransGrid and ElectraNet committed to the project in June 2021 following AER approval of the project costs.
  - a minor upgrade to the Victoria–NSW Interconnector, to access planned new capacity at Snowy Hydro and unlock renewable energy resources in western and north west Victoria
  - HumeLink – a transmission upgrade to reinforce the NSW southern network and increase transfer capacity between Snowy Hydro and demand centres, with completion due by 2025–26
  - network augmentations to support the Orana REZ in the central west of NSW and upgrade transfer capacity to major load centres, for expected completion in 2024–25[103]
  - Project Marinus – a proposed 1,500 MW capacity interconnector between Tasmania and Victoria to allow increased exports from Tasmania's renewable energy and storage resources
  - the Victoria to NSW Interconnector (VNI) West project, to allow for additional renewable generation in north west Victoria and address grid congestion and system strength issues
- third and fourth categories, which relate to projects that have been identified as potentially contributing to improved system outcomes but are not required immediately or are contingent on other projects or work programs.

Regulatory processes

Proposed transmission investments are subject to a cost-benefit analysis before they can proceed. The RIT-T assesses an investment proposal against credible alternatives, including non-network solutions.

The RIT-T has been streamlined to fast-track strategic transmission projects. The changes (which took effect in 2020) allow some parts of the regulatory process to run concurrently, avoid duplicating processes such as modelling in cost–benefit assessments and allow regulatory requirements to be met *before* dependant generation projects are committed (section 1.6.2).[104] In August 2020 the AER published guidelines on how AEMO should undertake analysis and consultation in the ISP, and on how transmission businesses should apply the RIT-T to actionable ISP projects.

In 2021 the AER published guidance on its approach to assessing the costs of 'actionable' ISP projects for inclusion in the regulatory asset base, to support efficient and timely delivery.[105] In April 2021 the AER approved $45 million to upgrade the Victoria to NSW Interconnector to help secure electricity supply to homes and businesses after Liddell power station's closure in 2023. The upgrade is the first 'actionable project' to progress under new rules governing the ISP. Average residential customers in NSW will pay an estimated extra $1 on their bills in 2022–23 as a result of this decision.[106]

In May 2021 the AER approved funding of $2.3 billion in efficient costs for the proposed South Australia–NSW interconnector (Project EnergyConnect) – 4% less than the proposal from TransGrid and ElectraNet.[107]

103 AEMO, *2020 Integrated System Plan*, July 2020, p 14.

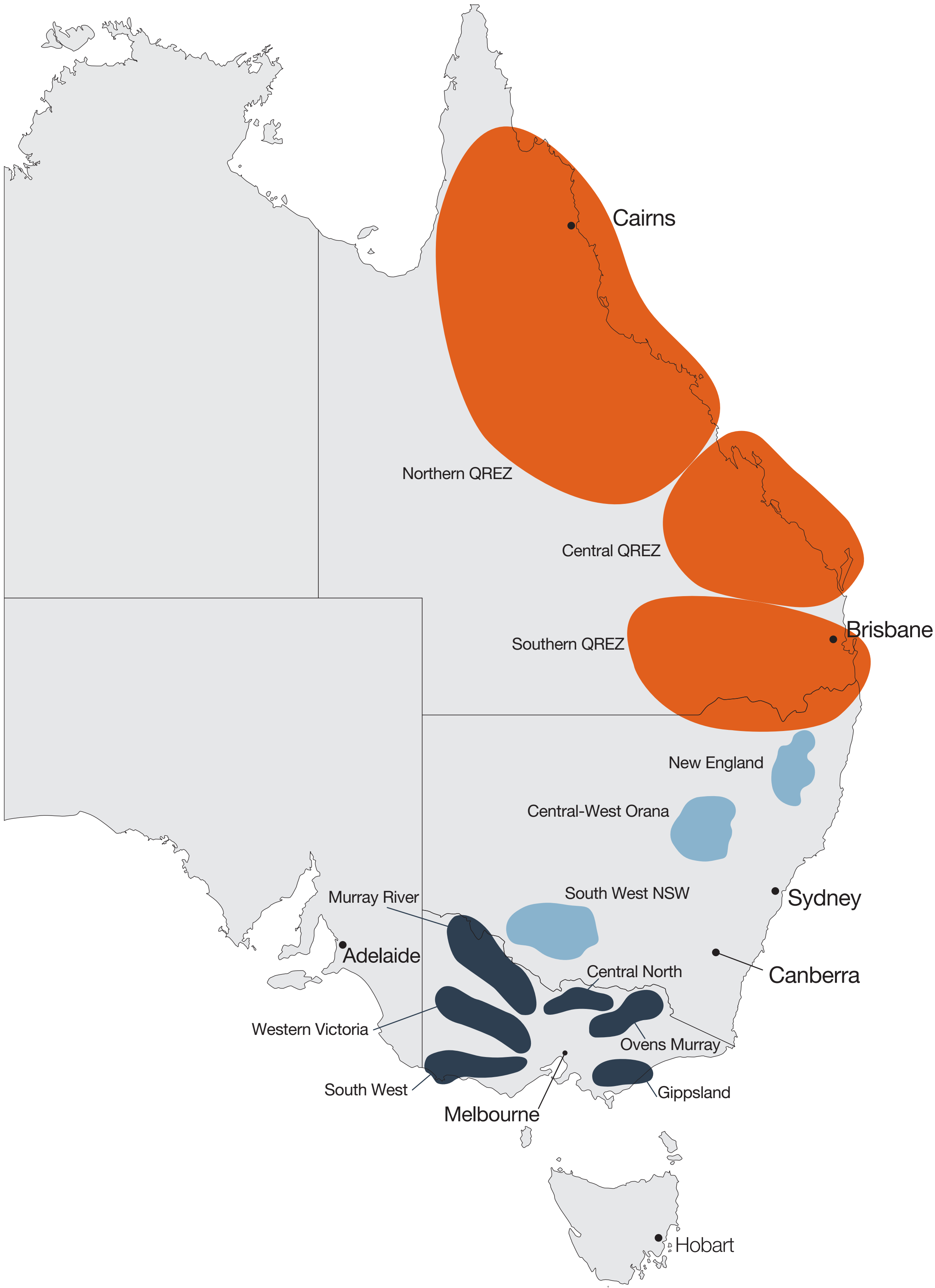
104 CoAG Energy Council, Energy Security Board, 'Actionable ISP final rule recommendation', CoAG website, accessed 27 March 2020.

105 AER, 'Regulation of large transmission projects' [media release], 17 November 2020.

106 AER, 'AER approves costs for Victoria to New South Wales Interconnector' [media release], 13 April 2021.

107 AER, 'AER approves costs for Project EnergyConnect' [media release], 31 May 2021.

Figure 1.16 Renewable energy zones



Note: The NSW Government has not mapped the location of the planned Hunter and Illawarra REZs.

Source: Department of Environment, Land, Water and Planning, Victoria, *Renewable energy zones*, DELWP website, accessed 1 June 2021; NSW Government, *Renewable energy zones*, NSW Government website, accessed 1 June 2021; Department of Energy and Public Works, Queensland, *Queensland renewable energy zones*, DEPW website, accessed 1 June 2021.

Challenges to ISP transmission projects

In 2021 the ESB reported that challenges are emerging in building new actionable ISP projects. These include planning issues, community concerns, biodiversity, Indigenous heritage, difficulties getting access to land and reluctance by networks to take risk and cope with financing very large projects. Unaddressed, these issues have the potential to result in delays and increased costs. In some cases, the Commonwealth and relevant state jurisdictions are underwriting and supporting projects.[108]

TransGrid and ElectraNet raised concerns about the ability of network businesses to finance large transmission projects. In April 2021 the AEMC rejected a rule change proposal in relation to revenue recovery for actionable ISP projects to be developed by these network businesses. The AEMC considered that current arrangements do not pose a barrier to financing actionable ISP projects. The AEMC also considered that making the rule change would likely substantially increase costs to consumers in the near to medium term.[109]

Community concerns can be addressed through a RIT-T dispute process. Upon receiving a dispute, the AER assesses the transmission business's compliance with the RIT-T. In 2019 the South Australian Council of Social Service (SACOSS) lodged a dispute over ElectraNet's application of the RIT-T to the proposed South Australia–NSW interconnector. The AER found that ElectraNet had met the requirements of the test.

Allocating costs of transmission interconnectors

While transmission interconnectors provide national benefits, they are largely paid for by customers who happen to live in the states in which they are built. The approach raises issues of fairness and has come under scrutiny. For instance, the Marinus Link project linking Tasmania with Victoria will only proceed if agreement is reached on how the cost of the project will be recovered. The issue has the potential to delay the project.

There is also a debate as to whether generators should share in the cost of transmission investment. The ESB has provided advice to Energy Ministers on a fair method for allocating transmission costs to better align the costs and benefits of network investment and governments are conducting further analysis.[110]

1.6.2 Access pricing

Coordinating transmission and generation development will help overcome some of the traditional inefficiencies in connecting new plant to the grid. But reform is needed to achieve this coordination.

Price signals for investors as to where the network has spare capacity for new connections are currently limited. Every generator and customer in a region receives or pays the same price (adjusted for loss factors), which is determined at a single point in the region called the reference node. Marginal loss factors provide a limited signal on how connecting in a weak network area might impact future earnings. But marginal loss factors have become increasingly volatile and, therefore, difficult to interpret or rely on (box 1.6).

The ESB is exploring medium term pricing reforms for congestion management as a focus of its NEM 2025 reforms. Options include charges imposed each dispatch interval on generators contributing to network congestion; connection fees for new generators that reflect congestion costs caused by their connection; and generator transmission use of system charges that reflects the relative cost of providing transmission infrastructure at a given point on the network.

The proposed congestion management charge would reflect a generator's marginal impact on the cost of congestion in each dispatch interval. This would remove incentives for 'disorderly bidding' – where generators offer capacity below cost to ensure dispatch – when the network is congested. Money received through the congestion charge would then be rebated to generators based on their availability. To encourage new generation investment within REZs and other areas of new transmission capacity, the rebate could be limited to new generators that locate within these zones.

In the longer term, the ESB is exploring a more comprehensive access solution in the form of locational marginal pricing and financial transmission rights.

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108 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 78.

109 AEMC, *Rule determination – participant derogation – financeability of ISP project (ElectraNet)*, April 2021.

110 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 75.

Under AEMC proposals announced in 2020, generators would receive a local price based on the marginal cost of supplying electricity in their specific network area. The price would account for congestion and losses in that area.

Generators would have access to new hedge products (financial transmission rights) to manage the risks of congestion and transmission losses. The hedges would effectively pay a generator the difference between the local and regional price. The AEMC argued the combination of local pricing and financial transmission rights would improve incentives for generators to connect to efficient areas of the network, thereby lowering costs to customers.

Box 1.6 Existing price signals for new plant

As the National Electricity Market's (NEM) generation fleet becomes more geographically dispersed, and new plants locate further from the existing grid, energy losses from the system are rising. When electricity is transported across a network of poles and wires, some of it is lost as heat. These losses increase as more generators locate far from demand centres, because power has to travel further to reach customers. Across the NEM, transmission losses equate to around 10% of all electricity transported between power stations and customers.[111]

A generator's earnings from selling electricity are scaled down to reflect this loss of energy. Generators that locate near the end of the line, where transmission is weak, have a relatively high loss factor. As a result, their earnings can be significantly scaled down. This outcome appropriately signals to developers that locating new plant in a weak network area poses risks to future earnings. In this way, loss factors provide a price signal that discourages investment in inefficient locations.[112]

In the NEM, this signal is applied through *marginal loss factors* (MLFs), which estimate the percentage of the next (marginal) unit of electricity sent into the grid that is likely to reach customers rather than being lost. The Australian Energy Market Operator (AEMO) forecasts the MLF for each generator annually, based on forecast losses between a generator and the regional reference node (the place in a region where wholesale electricity prices are set).

The increase in renewable generation in weaker (often remote) parts of the grid can cause large changes in loss factors. The planned connection of substantial solar generation in north and central Queensland led to MLFs in the region being scaled back in each of the 3 years to 2020–21. Loss factors were also scaled back in 2020–21 for some other regions where network limitations constrain generation output, including areas of north west Victoria, south west NSW, the south east and Riverland areas of South Australia, and several parts of Tasmania.[113]

MLFs provide a partial price signal on where to invest in new generation. But, with the sheer volume of new renewable generation connecting to the system, the usefulness of MLFs as a price signal is breaking down. Price signals for locating new plant should provide relatively stable longer term guidance, but MLFs have become increasingly volatile. To help decision making, the AEMC in 2020 amended the calculation process to increase transparency and improve predictability for investors.[114]

The MLFs are also only a partial signal. While they account for transmission losses caused by a generator connecting in a weak network area, they do not capture network congestion costs, which are borne by the whole market.

111 AEMO, 'Loss factors and regional boundaries', AEMO website, accessed 21 May 2020.

112 AEMC, *Transmission loss factors*, fact sheet, November 2019.

113 AEMO, *Regions and marginal loss factors: FY 2020–21*, April 2020.

114 AEMC, *Transmission loss factors, Final determination*, 27 February 2020.

1.7 Government schemes

Governments at all levels are undertaking unilateral (or bilateral) policy initiatives to manage aspects of the energy market transition. The schemes include major investments in publicly owned generation and storage, programs offering financial assistance for private grid scale projects, and regulatory interventions to streamline investment approvals.

The schemes often embody broader policy objectives than maintaining reliability and security. Examples include supporting community transition and jobs or delivering low emissions and renewable energy policy targets.[115]

While government intervention can help manage an identified market issue, its wider market impacts are complex. In particular, intervention can distort market signals, affecting private sector investment decisions. The addition of capacity from government-backed schemes places downward pressure on the current and projected energy prices, putting resources not supported by government backing at a competitive disadvantage, making it more difficult for them to attract investment. Lower energy prices also makes it difficult for thermal plants to maintain commercial viability and may lead to exits of thermal plant faster than anticipated.[116]

The AER has previously noted that a key driver behind increased government intervention appears to be the risk that short term price signals may not deliver significant investment in dispatchable generation at the current time.[117]

The ESB noted a number of government interventions appear to be driven by an intolerance for sustained high prices that may be needed to prompt a market-led investment response. The ESB found that rewarding resources outside the market increases the risk of distortions, especially when interventions are delivered inconsistently and in an uncoordinated way.[118]

The ESB recognised that jurisdictional investment schemes are likely to be an enduring feature of the energy sector as governments seek to manage risks associated with the energy transition. It is working with governments and industry on a more consistent NEM-wide approach to the various schemes that preserves the role of spot and contract markets in providing the primary signal for investment.[119]

1.7.1 Incentivising private capacity investment

Australian governments offer a range of financial incentives for private investment in generation and storage capacity. Some schemes offer direct subsidies or grants. Others underwrite investment through debt or equity support or through measures such as selling 'contracts for difference' that provide financial certainty for investors. Some schemes use a mix of approaches.

Underwriting new generation investment

Alongside ongoing funding schemes run by ARENA and the Clean Energy Finance Corporation (CEFC) (box 1.1), the Australian Government launched the UNGI program in 2019. The program offers incentives for 'firm' and 'firmed' capacity targeted at lowering prices, increasing competition and increasing reliability.

The first registrations of interest led to a shortlist of 12 projects: 6 pumped hydro projects (including Battery of the Nation), 5 gas projects, and a proposed upgrade of the Vales Point black coal fired generator (which has since been cancelled).

115 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 18.

116 ESB, *Post-2025 market design directions paper*, January 2021, pp 16, 22.

117 AER, *Wholesale electricity market performance report 2020*, December 2020.

118 ESB, *Post-2025 market design directions paper*, January 2021, pp 16, 21, 24.

119 ESB, *Post-2025 market design directions paper*, January 2021, p 29.

From the shortlist, the Australian Government announced 2 successful projects in January 2020:

- APA Group's proposed 220 MW gas generator in Victoria to provide fast-start generation to balance the increase in intermittent renewables in that state
- Quinbrook Infrastructure Partners' 132 MW gas generator in Queensland to help meet peak demand in Queensland and NSW, increase competition and complement an upgrade to the Queensland–NSW Interconnector.[120]

An agreement to fund these projects had not been reached by early 2021 due to stalled progress in implementing the Grid Reliability Fund.[121]

State and territory government schemes

The Victorian Government's Renewable Energy Target, the Queensland Government's Renewable Energy Target and the ACT Government's 100% Renewable Energy Target are backed by programs to underwrite investment. The governments run reverse auctions to secure target levels of new renewable generation capacity, with successful applicants receiving a guaranteed minimum price for generation output from the plant. The NSW Government's Electricity Infrastructure Roadmap also proposes significant underwriting of generation investment.

1.7.2 Public investment in generation capacity

Despite strong investment in renewable capacity, private sector investment in 'firming' or 'dispatchable' capacity in recent years has been negligible. To fill the gap, the Australian Government and some state governments have announced new public sector investment in electricity generation, storage and transmission projects.

Snowy 2.0

Among major initiatives, in 2018 the Australian Government committed to expanding Snowy Hydro by using pumped hydroelectric technology. The expansion will increase Snowy Hydro's pumped hydroelectric generation capacity by around 2,000 MW – a rise of 50% – adding 175 hours of storage to the NEM. The project will construct an underground power station and about 27 kilometres of power waterway tunnels to link existing reservoirs. The underground power station will pump water to the upper reservoir when electricity prices are low. When prices are high, it will generate electricity by releasing water to flow down through the underground power station back to the lower reservoir. Approvals for main works on the project were received in May 2020. The project is forecast to start producing power from the first of 6 new generators by early 2025.

In 2021 the Australian Government also committed funding for Snowy Hydro to build a 660 MW gas powered generator in the Hunter region of NSW by 2023 after declaring that committed private investment is insufficient to fill the gap left by the closure of the Liddell power station.[122]

Battery of the Nation

In April 2017 the Australian and Tasmanian governments announced a feasibility study on expanding the Tasmanian hydroelectric system. The expansion would deliver up to 2,500 MW of additional capacity, including through a pumped hydro project at Lake Cethana and redevelopment of the Tarraleah hydropower scheme. Initial studies of the project have been supported with $5 million in funding from ARENA.

Alongside the Battery of the Nation project, planning is progressing on a new interconnector between Tasmania and Victoria to support an expansion of Tasmania's renewable energy capacity. A business case for the 1,500 MW Marinus Link was completed in 2019, and in 2021 TasNetworks was progressing project design and approvals. The project will only proceed if an agreement is reached on allocating costs of the project across NEM regions.

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120 The Hon Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Initial support terms for two new generation projects agreed' [media release], 23 December 2019.

121 The Clean Energy Finance Corporation Amendment (Grid Reliability Fund) Bill 2020 was introduced into the House of Representatives in August 2020 but at May 2021 had not been passed.

122 The Hon Angus Taylor MP, 'Protecting families and businesses from higher energy prices' [media release], 19 May 2021.

CleanCo

In December 2018 the Queensland Government launched CleanCo – a state-owned corporation focused on meeting Queensland's 50% Renewable Energy Target by 2030. CleanCo has a target to support 1,400 MW of new renewable capacity by 2025 through a mix of building, owning and operating assets and investing in private sector projects.

In 2020 the Queensland Government committed $500 million into a Renewable Energy Fund, allowing increased public ownership of commercial renewable projects and supporting infrastructure.[123] In June 2021 the Government increased funding by $1.5 billion to support expansion of the renewable energy and hydrogen industries.[124] Investments from the fund are expected to be made progressively over the next 3 years.

Grid scale batteries

South Australian Government support led to the development of the first scheduled battery in the NEM – the 100 MW Hornsdale Power Reserve. The battery has helped lower the cost of frequency control services in the region. Its capacity was expanded to 150 MW in 2020.

The Victorian Government's first expedited project under its new transmission project approval framework was to fast-track AEMO's procurement of a 300 MW battery to increase import capacity of the Victoria to NSW Interconnector in peak demand periods. The battery will be in place by summer 2021–2022.

In May 2021 the NSW Government entered into a services agreement to underpin development of a 100 MW battery in the south west of the state. The agreement forms part of a long term retail contract with Shell Energy to provide electricity for government-run facilities.

123 Queensland Government, *Budget strategy and outlook 2020–21*, chapter 8, November 2020.

124 The Honourable Annastacia Palaszczuk, Premier and Minister for Trade '$2 billion investment to power more jobs and more industries through cheaper, cleaner energy' [media release], 10 June 2021.