IES 2019

Overview

In 2019 Australia's electricity system is being disrupted by a decade-long, uncontrolled experiment in high renewables integration. This has created both valuable lessons and serious problems. While only a small economy by global standards, the experience of the Australian "transformation" is a cautionary tale for others. Prudent management of the decarbonisation and transformation of Australia's electricity supply has been rendered impossible by polarised political division over climate change and energy policy. This resulting dysfunction has resulted in rising electricity prices, growing inequity and increased reliability risk. These deteriorating conditions have created a negative feedback loop: increasing government intervention in electricity markets and increasing political division.

The Australian electricity "experiment" has comprised a range of government policies forcing about 27 gigawatts of wind and solar PV into Australia's two relatively small and isolated electricity grids. About 40 per cent of the large-scale renewable capacity has been installed in South Australia, a small and relatively isolated state in south-central Australia. This state now derives about 50 per cent of its total generation from wind and solar PV. 20 per cent of Australian households now host rooftop solar PV panels (2.1 million households).

Almost no firming generation has been built to support this scale of variable renewable generation. Over the past decade more than 5000 megawatts of coal fired generation has exited the market due to age or unsustainable market conditions. Remaining coal fired generators are increasing output to meet the gap in supply but suffering from zero or negative wholesale prices when renewables output is high. There is increased activity to increase transmission between some states.

Key take outs from this uncontrolled experiment to date is the:

- Commercial and technical incompatibility of variable renewable generation at scale with traditional baseload generators (coal, nuclear);
- Increasing value (and scarcity) of ancillary services in high renewables penetration grids as conventional generators and sources of these services exit the market;
- Increased incidence of low inertia and diminished system strength during periods of high renewables generation;
- Rapid uptake of distributed generation technologies leading to perverse outcomes, like rooftop solar PV forecast to supply more than 90 per cent of minimum demand in smaller grids by 2025, with associated challenges of managing system strength, inertia and frequency control;
- High penetration of rooftop solar PV (well over 50 per cent of dwellings in some suburbs of Adelaide and Brisbane) resulting in chronic over-voltages in some parts of the distribution network;
- Increasing equity challenges as volume-based residential pricing allows solar PV households to greatly reduce their contribution to system costs;
- Increased price volatility from high penetration of variable renewable generation which has not, so far, created sufficient arbitrage opportunities for existing storage technologies to be viable without significant government assistance;
- The critical relationship between generation and transmission in system planning for high renewables generation systems.

These will be discussed in more detail in this paper.

Background

Like most economies, Australia's electricity system reflects its geography. Australia is a large island continent between the Pacific and Indian Oceans in the southern hemisphere. It is similar in size to western Europe or continental USA, and yet has a population of just 24 million people. About 20 million of these live near the coast in south-eastern Australia (Sydney, Melbourne, Brisbane and Adelaide). Around 90 per cent of the Australian population live in cities or regional centres.

Most of the population live in a warm/Mediterranean or sub-tropical climate. The temperate climate means residential demand for electricity is mild for much of the year, with summer and winter demand peaks. A mild climate enabled the building of large, poorly insulated dwellings during the 20^{th} century. Residential demand accounts for about 30 per cent of total electricity consumption.

For renewable generation, Australia has high quality wind and solar resources. It has average wind speeds across southern Australia of more than 8 m/s and solar irradiation in excess of 20 MJ/m2 across central and northern Australia.

Australia's industrial economy has been framed by its resources industry. Australia is a net energy exporter, with abundant reserves of black and brown (lignite) coal along the east coast, conventional gas fields across the north-west and central Australia and unconventional gas fields scattered across the continent. Australia still relies predominantly on black coal (54 per cent) for electricity generation, followed by brown coal/lignite (20 per cent), gas (14 per cent) and hydro (7 per cent).

In the second half of the 20th century, industrial demand for electricity increased on the back of abundant and low-cost coal-fired generation. This attracted investment in metals processing which is now in decline as a result of rising electricity prices and competition from low-cost producers in Asia.

Electricity systems

Australia has two main electricity markets – the National Electricity Market (NEM) with a capacity of 54GW covering the eastern states including Sydney, Melbourne, Brisbane and Adelaide and the Wholesale Electricity Market (6.2GW) which operates around the city of Perth. The Australian Energy Market Operator (AEMO) oversees trading and market operations in both markets.

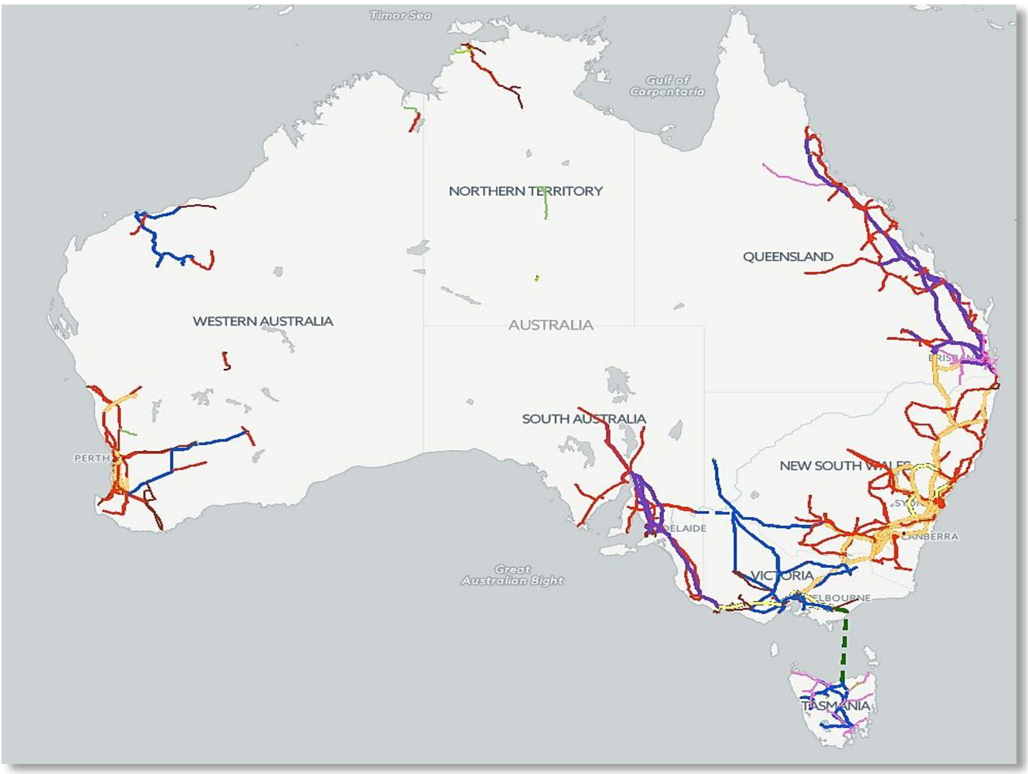
The NEM was created in 1999 by linking the independent state electricity grids of the five south-eastern states – New South Wales, Victoria, Queensland, South Australia and Tasmania. The significant distances between state networks and the relatively low population density make the NEM one of the longest interconnected AC systems in the world.

It is an energy-only mandatory gross pool market with a high Value of Lost Load (VoLL) of $14,500 per MWh, encouraging active trading in forward contract markets to hedge price and volume risk. The liquidity of trading these derivatives (mostly swaps and caps) has been a key feature of the market. They have acted as a proxy capacity payment for generators, ensuring there was enough peaking capacity during high demand events (mostly very hot summer days).

Until around 2009 the NEM operated in a technical fashion not unlike the French electricity system, except it used coal fired generators rather than nuclear. At its peak in 2004, coal supplied 86 per cent of total generation. Peaks in demand were augmented by gas peakers and about 7 per cent from hydro generators in the Snowy Mountains (NSW and Victoria) and Tasmania. The abundance and proximity of coal fields close to major cities meant that Australia had one of the cheapest, and highest greenhouse emissions, electricity systems in the world.

The Wholesale Electricity Market (WEM) was created in 2006 incorporating capacity and wholesale electricity markets. The introduction of a capacity market reflected increased self-reliance on generation given the isolated nature of that grid. The WEM was established with an even mix of gas and coal generators.

Figure 1. Map of Australia's transmission system



Source: Australian Renewable Energy Mapping Infrastructure

The rest of remote and regional Australia is served by an archipelago of around 1000 remote electricity systems, ranging in scale from systems that supply small cities like Darwin to isolated farm stations and settlements. Most of these grids use gas and/or diesel for electricity supply, with increased augmentation from solar PV over time. The electricity system on King Island in Bass Strait (between Melbourne and Tasmania) has been integrating wind and solar PV into its island grid supplying about 1,500 residential dwellings and a cheese factory. It is a pioneer of renewable integration, operating at about 65 per cent of total supply.

Renewables

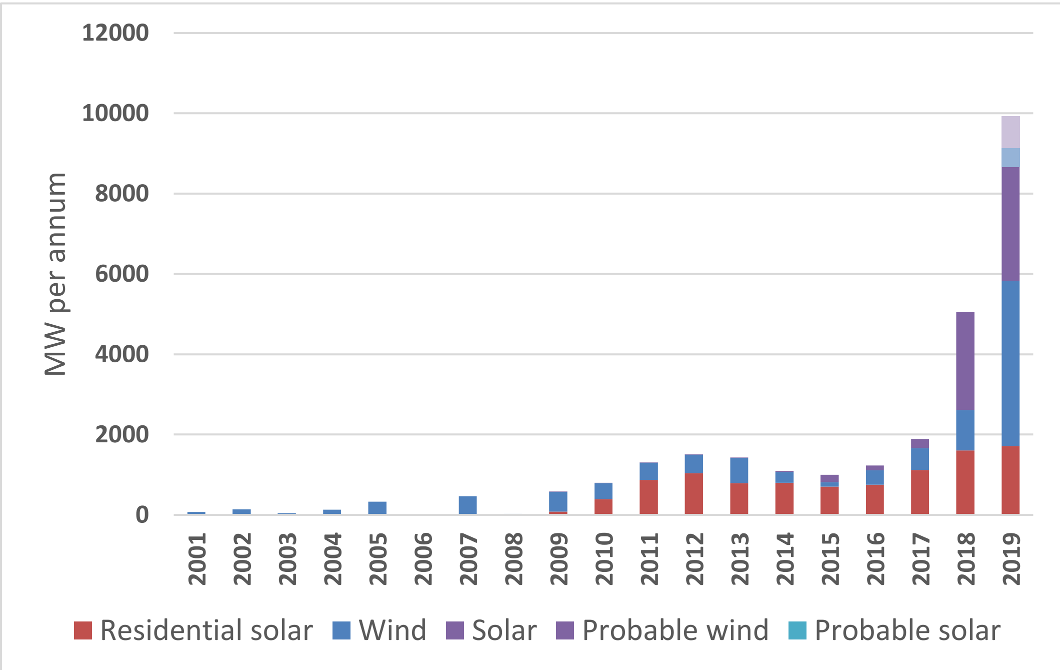
Australia's initial response to the risk of dangerous climate change was modest, reflecting the economic risk it posed to a high emissions energy consumer and exporter. A carbon tax was considered but rejected by the national government in 1995. A small rooftop solar PV subsidy scheme was introduced in 2000, followed by a small (2 per cent) Renewable Energy Target (RET) in 2001. The RET provided a subsidy for new renewable generators which effectively bridged the cost gap to the average wholesale price.

A major political shift occurred around 2006 during a protracted and severe drought (the Millennium Drought). By the end of 2006, dam levels in major cities like Melbourne and Sydney were as low as 25 per cent of capacity. Tight water restrictions were enforced on "traditional" Australian household activities like watering the lawn, filling backyard swimming pools and washing the car. The mostly urbanised and suburban Australian public associated the drought with climate change. Panicked by the severity of its impacts on them (dying gardens, unusable swimming pools) they demanded that governments immediately "fix" the problem.

This triggered two political responses. First, both the conservative government and the left-wing Labor opposition attempted to outbid each other with similar, but rival, emissions trading schemes. Second, the popularity of renewable energy triggered political support for the rapid expansion of existing support schemes. Subsidies and targets were rapidly increased by national and state governments.

Generous increases in financial support for household solar PV systems (upfront subsidies plus high feed-in tariffs) coincided with a sharp drop in system costs, resulting in sustained expansion in installations in the suburbs of Australia's major towns and cities. In 2009 the renewable energy target was increased to 20 per cent of generation by 2020.

Figure 2: Installation of intermittent renewable generation in Australia, MW per annum, 2001-19



Source: Clean Energy Regulator

The RET scheme used a tradable certificate market to bridge the gap between the wholesale price and renewable generation. Retailers were required to surrender certificates proportionate to their market share each year. The scheme also allowed for banking and borrowing of these certificates and was reviewed in 2015 by the Federal Government, with concern at the time that it may close the scheme.

The net effect of these design features and declining cost for wind and solar PV has resulted in a rapid scale up of investment since 2016. About 27 GW of new wind and solar PV will have been installed in Australia by the end of 2020 Australia will join the renewables superpower club of a kilowatt of renewable capacity per capita in early 2020. The two other members are Germany and Denmark.

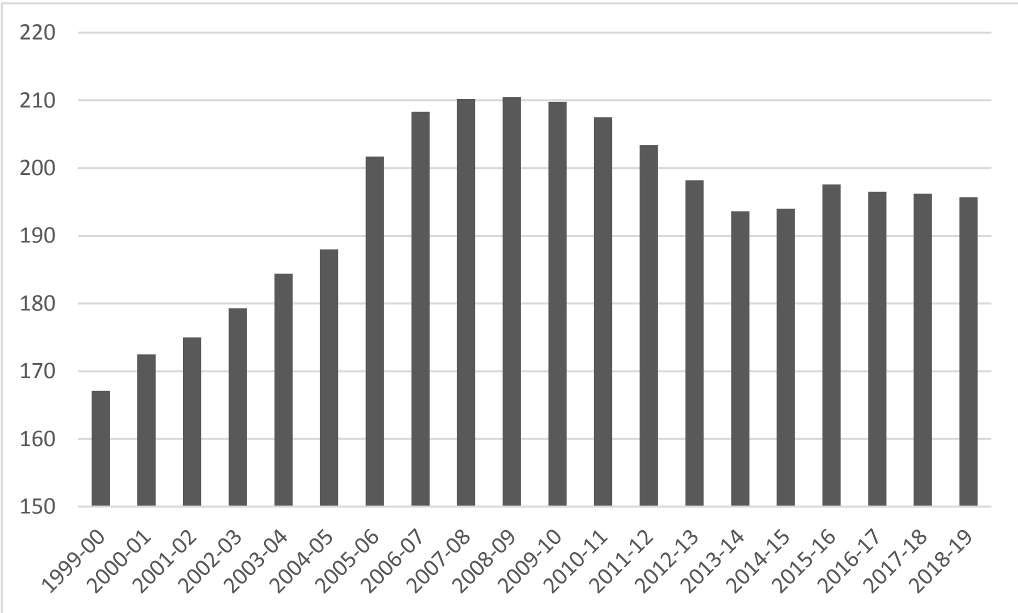
Australia's current per capita installation rate of intermittent renewables is twice as fast as Germany and five times faster than Japan or the US. Australia will surpass its legislated 2020 utility scale renewables target, while more than 2 million Australian households have installed solar PV systems.

By contrast, attempts to implement an emissions trading scheme collapsed in 2008 following the Global Financial Crisis. There have been five subsequent attempts to design and legislate national climate and energy policy since then. All have failed (the national government legislated a carbon tax in 2012, but it was repealed three years later). Energy and climate policy has remained highly politicised and divisive. It has defaulted to a unitary focus on subsidies for renewable generation. As a result, almost all new investment in electricity generation in Australia over the last decade has been either wind or solar PV.

Increased renewable generation into falling demand

In 2009 it was assumed the new renewable generation would partly displace new gas fired generation which was expected to be built to meet anticipated growth in electricity demand. Like most developed economies, Australia's electricity demand had grown at a similar rate to Gross Domestic Product since the 1950s.

Figure 3: National Electricity Market demand since 1999-00 (TWh per annum)



Source: Australian Energy Regulator

Coincidentally, just as new renewable generation was being mandated by national legislation, electricity demand began to decline. This softening demand for electricity was driven by a range of factors: continued improvements in the efficiency of appliances and equipment, increased installation of rooftop solar PV, the price effect of rising electricity prices and by structural changes in the economy: the closure of metals processing (aluminium) and manufacturing (cars), and a broader transition away from energy-intensive manufacturing toward the construction and services sectors.

Factors still driving increases in demand were continued population growth and the use of electricity to compress natural gas at three new LNG export facilities (at Gladstone in Queensland), which started to come online in 2015. Demand is expected to gradually contract with continuing uptake of distributed solar PV and further closures of Australia's remaining four aluminium smelters anticipated in the next decade.

Storage

While renewable generation has increased rapidly in Australian markets, there has been little investment in its natural complement: storage. The NEM had about 2.3 GW of pumped hydro storage capacity as legacy investments from the 20th century. While policies to drive investment in renewable generation have done that spectacularly, this has not been accompanied by any policies to promote investment in firming generation.

The biggest storage investment to date is the much publicised 100MW/129MWh Tesla battery installed by Neoen at Hornsdale in South Australia with significant financial assistance from the state's Government. Unsubsidised battery investments have typically been about a quarter of this size.

While the Hornsdale battery has had only a minor impact in terms of load-shifting (its 129MWh capacity is less than 0.5% of South Australia's daily load), it has had a significant impact on ancillary services. In particular, its ability to very rapidly respond to frequency drops has led to a review of how fast frequency response markets should be designed and operated.

Table1. Large scale storage in the National Electricity Market

Project	Owner	State	Type	Capacity	Completion
Operational					
Tumut 3	Snowy	NSW	Pumped hydro	1800MW	1973
Wivenhoe	CS Energy	Qld	Pumped hydro	500MW	1984
Hornsdale	Neoen (Tesla)	SA	Li-ion	100MW/129MWh	2017
Kennedy Energy Park	Windlab	Qld	Li-ion	2MW/4MWh	2018
Lake Bonney	Infigen	SA	Li-ion	25MW/52MWh	2018
Ballarat	EnergyAustralia	Vic	Li-ion	30MW/30MWh	2018
Dalrymple	AGL/ElectraNet	SA	Li-ion	30MW/	2019
Lincoln Gap	Nexif	SA	Li-ion	10MW	2019
Gannawarra	Wirsol/Edify	Vic	Li-ion	25MW/50MWh	2019
Under development					
Snowy 2.0	Snowy Hydro	NSW	Pumped Hydro	2000MW	2026

The major storage project under development is Snowy 2.0 – a major retrofitting of pumped hydro capacity in the existing Snowy River hydroelectric scheme in southern New South Wales. This AUD $5.1 billion project has received $1.8 billion from the national government. It involves 27 kilometres of tunnels through rock and a power station built one-kilometre underground. It is expected to be completed in the second half of the 2020s.

There is a growing list of another 5.8 GW of prospective pumped hydro and battery storage projects. Most of these remain commercially unviable without further government support. The national government has created a project underwriting scheme which includes some of these projects. It appears likely, for at least the short term, that further storage capacity will require this kind of direct intervention to proceed.

Disruption

Australia's 20th century electricity system relied predominantly on a fleet of large coal fired generators built through the post-war economic boom. By 2000 they supplied about 87 per cent of total generation in the NEM and about half of total generation in the WEM. By 2009 the oldest of these generators were approaching the end of their operational life and required replacement. Since 2012, more than 5.6GW of capacity has been closed.

Table 2: Closures of coal fired power stations in Australia since 2012

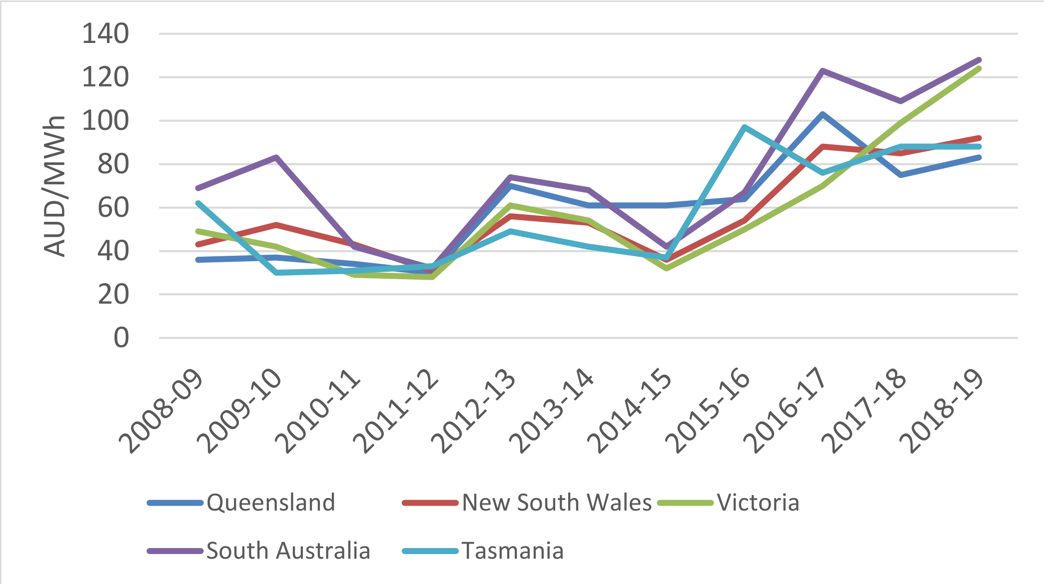
Power station	Name	Capacity	Date of closure
Swanbank B	Queensland	500	May 2012
Munmorah	New South Wales	600	July 2012
Collinsville	Queensland	180	December 2012
Morwell	Victoria	189	August 2014
Redbank	New South Wales	144	August 2014
Wallerawang C	New South Wales	1000	November 2014
Anglesea	Victoria	160	August 2015
Northern	South Australia	546	May 2016
Playford	South Australia	240	May 2016
Hazelwood	Victoria	1760	March 2017
Muja AB	Western Australia	240	September 2017

The incomplete political interventions by consecutive national governments created a deepening investment problem in Australia. Renewable generation was able to be built behind direct government subsidy. But firm generators were not. New high emissions coal fired generators were un-bankable because of their exposure to long term carbon risk. Combined cycle gas turbine plant (CCGT) did not have a material carbon price to enable it to bid in front of coal generators. Open cycle gas turbine plant OCGT, and later reciprocating engines, found the value of their operating peaks reduced by increased intermittent generation. Peaking generation was certainly required, but it was no longer commercially viable to build.

The investment case for gas generators deteriorated even further with the depletion of Australia's conventional onshore gas fields in the Cooper Basin. This supply of non-trade exposed low cost gas was replaced by higher cost unconventional fields. To commercialise these fields, developers began to build LNG export facilities to ensure access to global markets and pricing. The cost of Australia's east coast gas then re-set to this higher global market price.

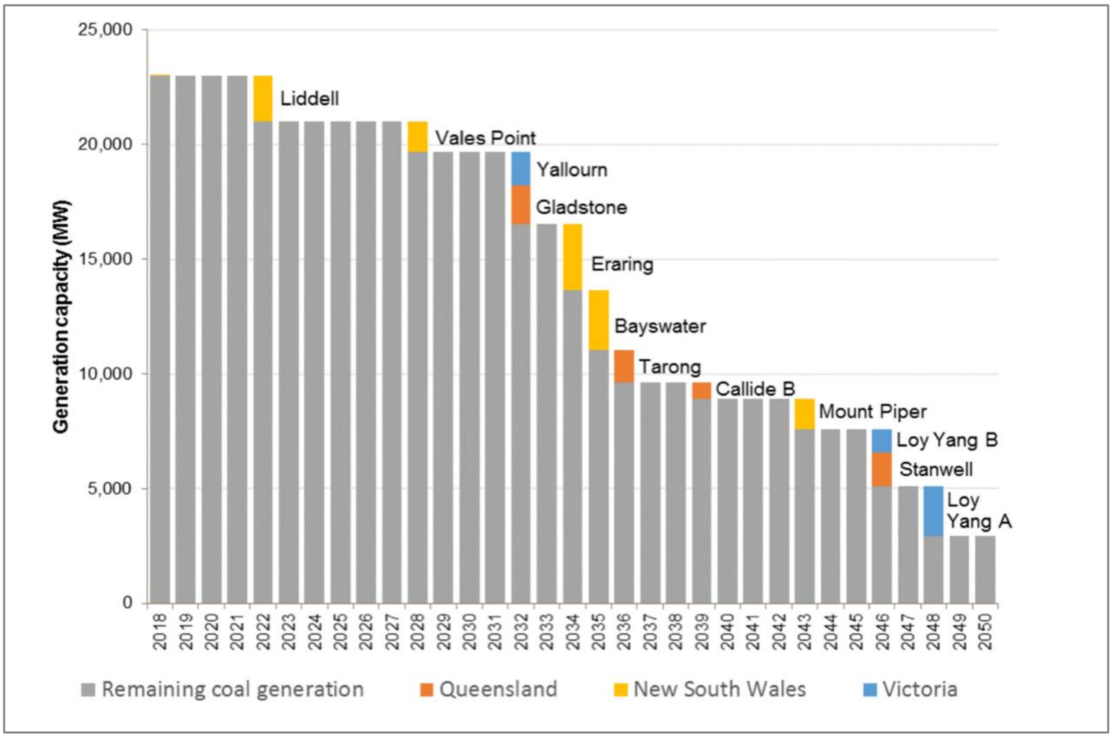
Increased intermittent renewable generation initially suppressed wholesale prices (the combined result of increasing supply and decreasing demand). It also started to increase the volatility of spot prices (reflecting its intermittency). Once coal generators exited and weren't replaced, liquidity in forward contract markets declined (unfirmed renewables cannot contract in futures markets if they cannot guarantee supply). Increased scarcity of low-cost coal generation was increasingly replaced by higher cost gas generation. Despite softening demand and increased intermittent generation, wholesale prices started to increase when firm generators existed the market. These price increases have been most pronounced in Victoria and South Australia, following the closure of a major power station in each state: Northern in South Australia in 2016 and Hazelwood in Victoria in 2017.

Figure 4: National Electricity Market wholesale spot price by state, 2009-19 (AUD/MWh)



Australia faces continued closure of coal fired generators. Based on an estimated 50 year working life, The National Electricity Market faces 5,000 MW of capacity closures over the coming decade and another 10,000MW early in the 2030s. The condition of the Australian electricity system is now becoming critical.

Figure 5: NEM coal generation fleet if plant retires as announced or at 50th year from full operation



In summary over the past decade:

- 27GW of intermittent generation installed into Australia's two main electricity grids with a combined total capacity of around 60GW.
- There is no agreement on a carbon price or any other national climate and energy strategy.

- Continued closures of ageing coal fired power stations, reducing supply of firm generation and increasing wholesale prices.
- Increased volatility in wholesale prices as intermittent generation increases.
- Reduced liquidity in forward contract (hedge) markets.
- System black in 2016 in South Australia, reduced reserve margins resulting in blackouts in Victoria in January 2019, and the threat of further blackouts in the summer of 2019-20.

Technical challenges and observations

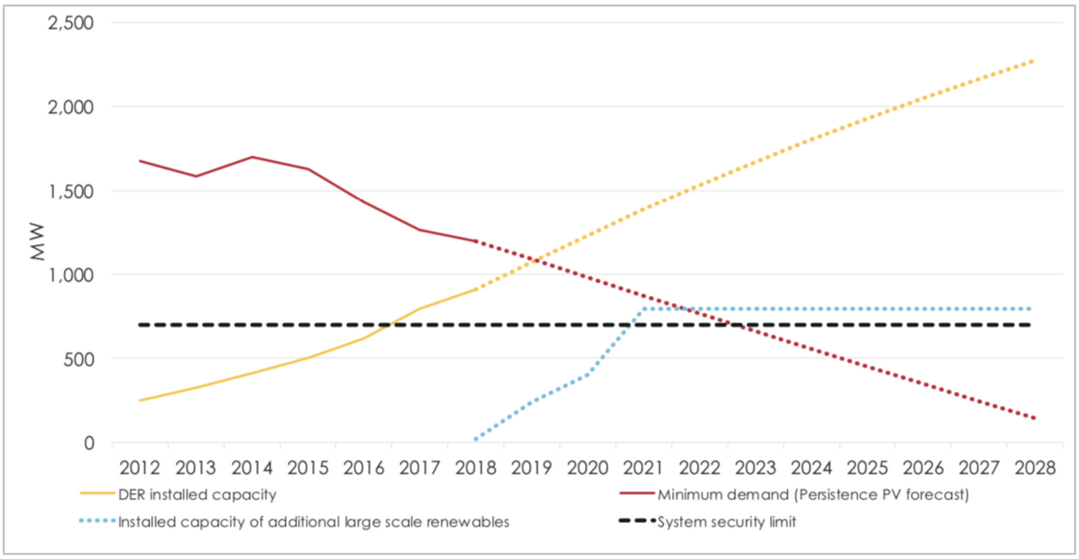
1. Distributed rooftop solar and minimum demand – Perth

The smaller WEM grid (around Perth in Western Australia) has a capacity of around 6GW. Total rooftop solar PV capacity is now approaching 1GW. This poses challenges for minimum demand events in the future, as operational demand is set to fall below the system security threshold of 700MW. On current rates of rooftop solar PV deploy this is expected to occur in 2022. This would equate to about 62 per cent of supply being met by distributed solar PV.

This problem is exacerbated because the existing rooftop solar PV is neither accurately monitored nor controlled. Residential solar PV systems are not currently required to have remote control/monitoring systems installed. This generation cannot be curtailed without disconnecting the loads they are connected to.

The share of intermittent generation is likely to increase further with new large-scale generation coming online now as part of the completion of the national Renewable Energy Target. The Perth grid has already experienced periods of 40 per cent of non-synchronous generation in 2018. Importantly, this grid is isolated – it is not connected to any other system. At this stage the solutions being proposed include forcing synchronous generation to run during these periods or the network will need to be significantly upgraded.

Figure 6: Minimum demand, distributed generation (solar PV) and system security limit in the Wholesale Electricity Market (WA)



Source: AEMO

Incompatibility of baseload and renewable generation at scale – South Australia

The design of Australia's Renewable Energy Target uses a certificate-based trading scheme to identify and finance the lowest cost types of generation, regardless of location or technology. The wholesale price in South Australia was consistently higher than other states in the NEM because it was the only state where the marginal cost of generation was set by gas. South Australia has excellent solar and particularly wind resources. As a result, South Australia attracted about 40 per cent of the renewable generation projects in the scheme.

Table 3: Generation and capacity in South Australia 2018-19

Fuel Type	Registered capacity		Electricity generated	
	MW	% of total	GWh	% of total
Gas	2,773	44.0	6,854	47.9
Wind	1,809	28.7	5,724	40.0
Rooftop solar	1,089	17.3	1,353	9.5
Diesel	265	4.2	32	0.2
Utility solar	230	3.7	303	2.1
Battery	130	2.1	41	0.3
Total	**6,296**	**100**	**14,307**	**100**

Source: AEMO, CER for rooftop solar capacity

The South Australian grid is relatively small and isolated (3.4GW), connected to neighbouring Victoria by two transmission lines providing capacity of about 25 per cent of its peak demand. By 2015 wind and rooftop solar PV accounted for more than 40 per cent of electricity generated in South Australia. This generation swings in and out of the market, always first in the merit order (zero marginal cost). Renewables now regularly contribute more than 70 per cent of the state's total generation.

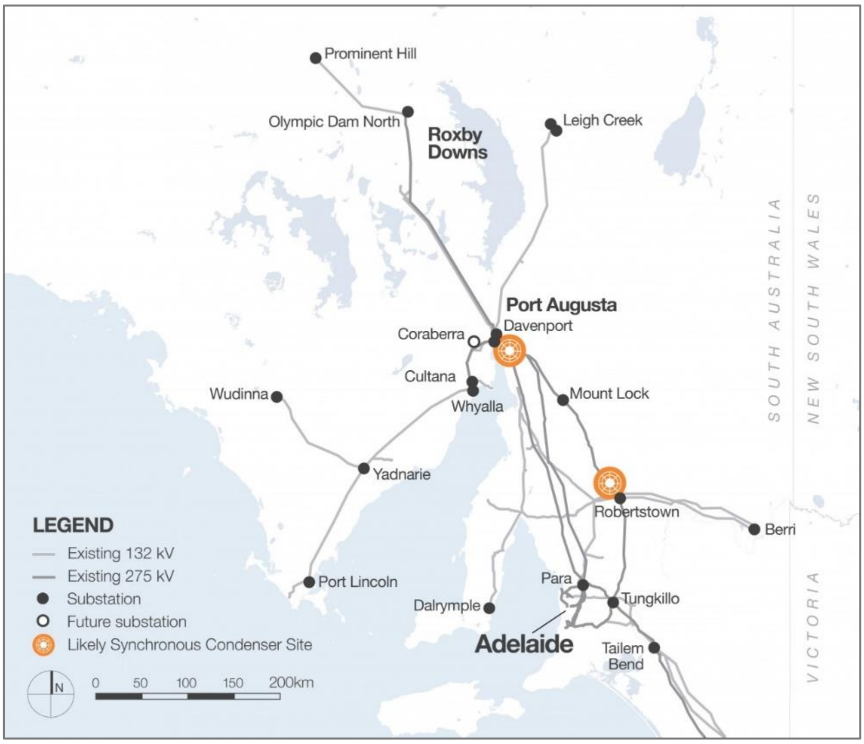
This growing tidal wave of renewable generation had a material impact on the commercial and technical performance of the state's last remaining coal fired power station, Northern at Port Augusta. It was not able to turn off and on every time the wind blew strongly. It's owners attempted to contract their own customer load and sought government assistance. They tried to operate the power station during the hotter summer months only. None of these measures were successful. In May 2016 Northern Power station closed. Another CCGT generator in South Australia also switched off half its capacity for the same reason.

What this experience suggests is that both operationally and commercially, large-scale baseload generators like coal and nuclear are not compatible with large scale intermittent generation in energy-only markets.

Need to augment inertia and system strength in high renewables grids – South Australia

Following the closure of the Northern Power Station and the system black in South Australia on 28 September 2016, there has been increased attention on the technical risks posed by running high intermittent renewables electricity systems. The system back was caused by insufficient firm generation operating during a major storm. Lightning strikes on multiple transmission lines cut off renewable supply from load centres, collapsing frequency, and the resulting rate of change of frequency function (ROCOF) triggered the interconnector to also switch off.

Figure 7: Likely synchronous condenser sites, South Australia



Source: ElectraNet

In October 2017 the market operator declared a gap in system strength in South Australia. The regional transmission provider ElectraNet has been given approval to build four synchronous condensers to provide system strength and inertia during high renewables generation. Currently the market operator is directing some firm generation on during periods of high renewables generation to provide these services. These condensers are likely to be completed by 2020.

Distribution Networks

Over-voltage problems caused by high penetration of rooftop solar PV

Household solar PV systems have become ubiquitous in the suburbs of Australian towns and cities. There are now more than 2.1 million systems installed, about 20 per cent of all residential dwellings. The distribution of these systems is not uniform. Rooftop solar PV is more prevalent in areas where there is a higher proportion of owner-occupier dwellings. It is more prevalent where there is a higher proportion of retirees. It is less common in suburbs with above average incomes.

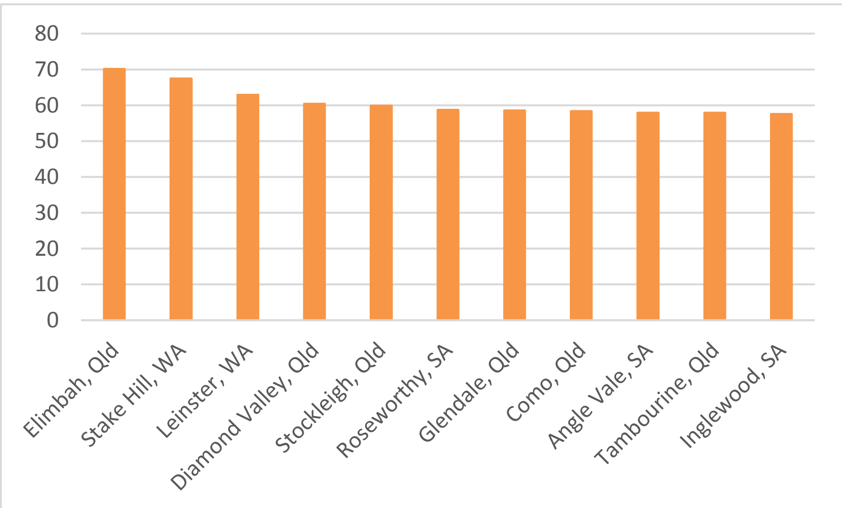
Figure 8: Proportion of dwellings with rooftop solar PV by state, Australia 2019

Source: APVI

This skewed distribution of systems means there are many suburbs and towns in high solar PV states (Queensland, South Australia and Western Australia) with penetration rates of well above 50 per cent or more of all dwellings. For example, the satellite town of Elimbah, north of Brisbane, has more than 70 per cent penetration rate of solar PV. During periods of low demand and high output (typically clear, sunny winter days), high density of solar PV systems can create significant over-voltage problems for the local distribution network.

In a trial of 150 distributed virtual power plants (solar and home battery) in Adelaide by AGL in 2017, voltages above 253 V were recorded for more than half the test households (the standard is 230 V)[i]. More than 25 per cent experienced voltages above 256 V, and a third of inverters tripped off more than once during the trial due to over-voltage issues. Remedying this (by tapping local transformers) imposes additional costs on networks, which transfers the cost of high solar PV generation onto all consumers.

Figure 9: Highest solar PV penetration rates, total percentage of dwellings with solar PV by suburb, Australia 2019



Source: APVI

Because distributed solar PV is net metered, it is unclear how much of the surplus generation from these systems can be utilised by the grid, particularly at times of lower demand and higher solar output. Despite this, there are no formal rules limiting PV installations or requiring them to demonstrate acceptable daytime voltages before being approved. Some network operators have started to limit solar connections where they have identified chronic over-voltage problems.

The challenges posed by increasing penetration of distributed energy resources are the subject of a major project by the system operator and Energy Networks Australia titled Open Energy Networks (OpEN).

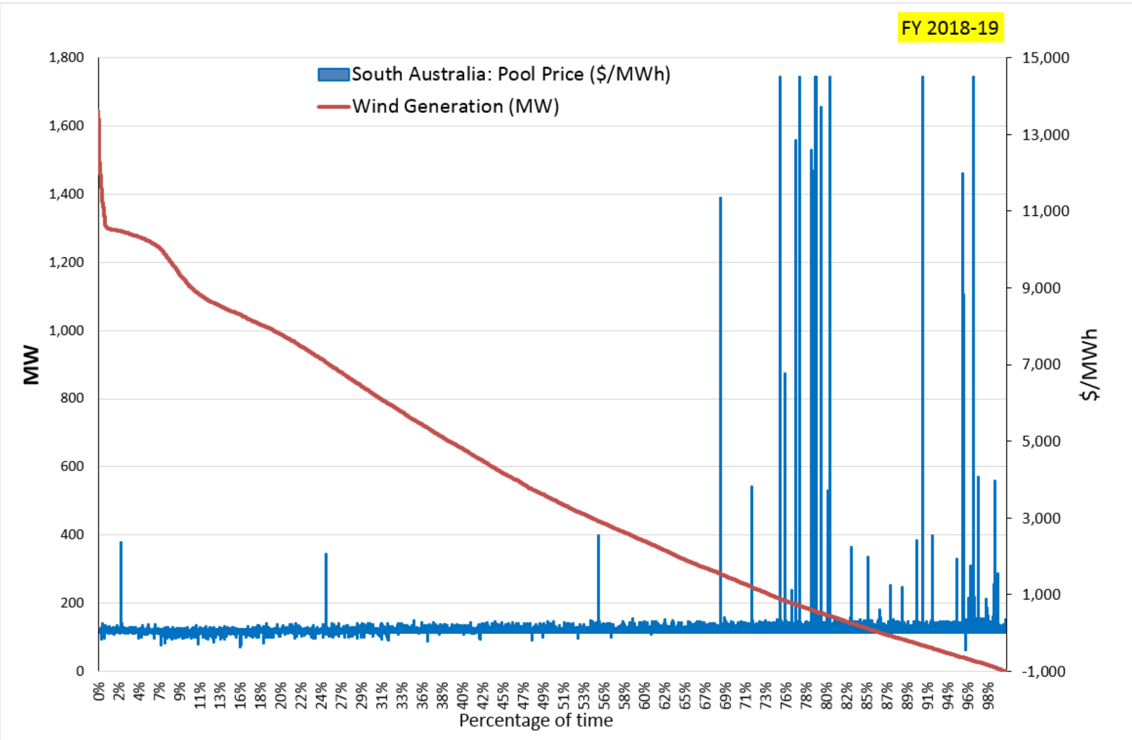
Modelling undertaken for OpEN by Australia's Commonwealth Scientific Research Organisation shows local distribution zone substations start to face serious voltage issues and equipment challenges from reverse flows of electricity back into the grid when penetration levels of solar PV reach about 40 per cent.

There are also great opportunities if Australia's enormous uptake of distributed energy resources can be optimised into Australia's electricity grids. OpEN's key objective is to investigate how best to maximise these potential benefits for the electricity system and for all customers. If optimal integration can be achieved, OpEN estimates more than $1 billion in savings could be delivered by 2030 through avoided investment in network augmentation.

The impact of high intermittent generation on price volatility – South Australia

High levels of intermittent generation have had two related but separate impacts on price volatility in the South Australian market. First the regular and increasing generation of wind and solar electricity reduced the frequency of high spot prices (above $300 MWh). When these events did occur after the closure of the Northern power station, they tended to me more volatile, with higher spot prices.

Figure 10: wind generation and South Australian pool price, 2018-19



At present, this volatility is not sufficient to drive investment in new storage capacity. South Australia does have a 100MW lithium ion battery built by Tesla and subsidised by the State Government. There are plans for three separate batteries of 100MW, 140MW and 250MW attached to respective solar farms. There are also two pumped hydro projects proposed of 250MW and 225MW. None of these proposed storage projects has yet started construction.

Emerging critical relationship between generation and transmission in system planning

The National Electricity Market (NEM) is effectively the connection of five state electricity grids via transmission lines. The low population density and longer distances has meant the level of transmission connection between states is significantly lower than in other geographically similar regions in the US or EU.

There are four main transmission connections linking the five states:

- The Queensland to New South Wales Interconnector (QNI) rated at 1078MW south and up to 600MW north.
- The Victoria-NSW interconnector (via the Snowy Hydro scheme) rated at up to 1350MW north and 1600MW south.
- The Basslink undersea cable between Victoria and Tasmania rated at 594MW north and 478MW south.
- The Heywood Interconnector between Victoria and South Australia, rated at 600MW west and 500MW east. (augmented by Murraylink at 220MW in both directions).

While increased interconnection has been a standard worldwide response to increased variable generation and the closure of thermal generators, Australia has been slow to act in this area. This was not helped by a system still largely driven by state-based planning and an investment test designed for new transmission to serve demand growth, not supply changes.

In July 2018, the system operator produced its inaugural Integrated System Plan (ISP), a cost-based 'engineering optimisation' plan forecasting transmission requirements for the NEM over the next 20 years. This identifies priorities for transmission projects, some requiring immediate action and others needed over the medium and longer term.

Modelling for the ISP shows that by spending eight to 15 per cent of the bulk system investment needed on transmission rather than generation will deliver total system cost savings of between $1.2 billion and $2.0 billion.

Modest upgrades to the interconnectors between NSW and Queensland and NSW and Victoria are likely to proceed later this year.

Other proposed transmission lines include a new link between South Australia and NSW, a second undersea cable linking Tasmania and the mainland (to allow more wind farms on Tasmania and to access up to 2000MW of proposed pumped hydro), and two separate transmission systems linking under construction pumped hydro Snowy 2.0 with major load centres in Sydney and Melbourne.

There are still further plans for transmission augmentation to enable renewables development in a number of renewable energy zones, identified for their wind and/or solar energy properties.

The challenge with transmission planning is to balance the requirement for greater connectivity with the need to attract new investment in firm generation. Related to this, the national rule maker is reviewing if Australia's open-access regime needs amendment to allow generators firmer access in return for financial contributions to transmission network costs.

Other current policy measures

In the absence of co-ordinated national climate and policy leadership, there are instead a suite of sometimes competing policy initiatives being discussed in Australia. The following list is by no means exhaustive.

- Victorian State Government has set a 50 per cent renewable energy target by 2030.
- Queensland State Government has set a 50 per cent renewable target by 2030 and created a government-owned CleanCo generation business to deliver it.
- The Federal Government has contributed AUD $1.8 billion to the Snowy 2.0 pumped hydro project, an augmentation of the existing Snowy Hydro Scheme adding up to 2000MW of new pumped hydro by late 2020s (Current cost AUD $5.1 billion).
- Implementation of the Retailer Reliability Obligation (RRO), designed to force retailers (suppliers) to fund new firm generation where there is an identified shortfall.
- A review of the design of the energy-only market in the NEM to be completed by the end of 2020 with possible implementation of reforms by 2025.
- A Federal Government program to underwrite new firm generation projects. 11 have been shortlisted, there are no criteria and no budget has been announced.
- A Federal parliamentary review of the feasibility of nuclear energy by the end of 2019. Nuclear energy has been banned in Australia since 1999.

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[i] VPP-SA Public Milestone Report, AGL, 31 July 2017