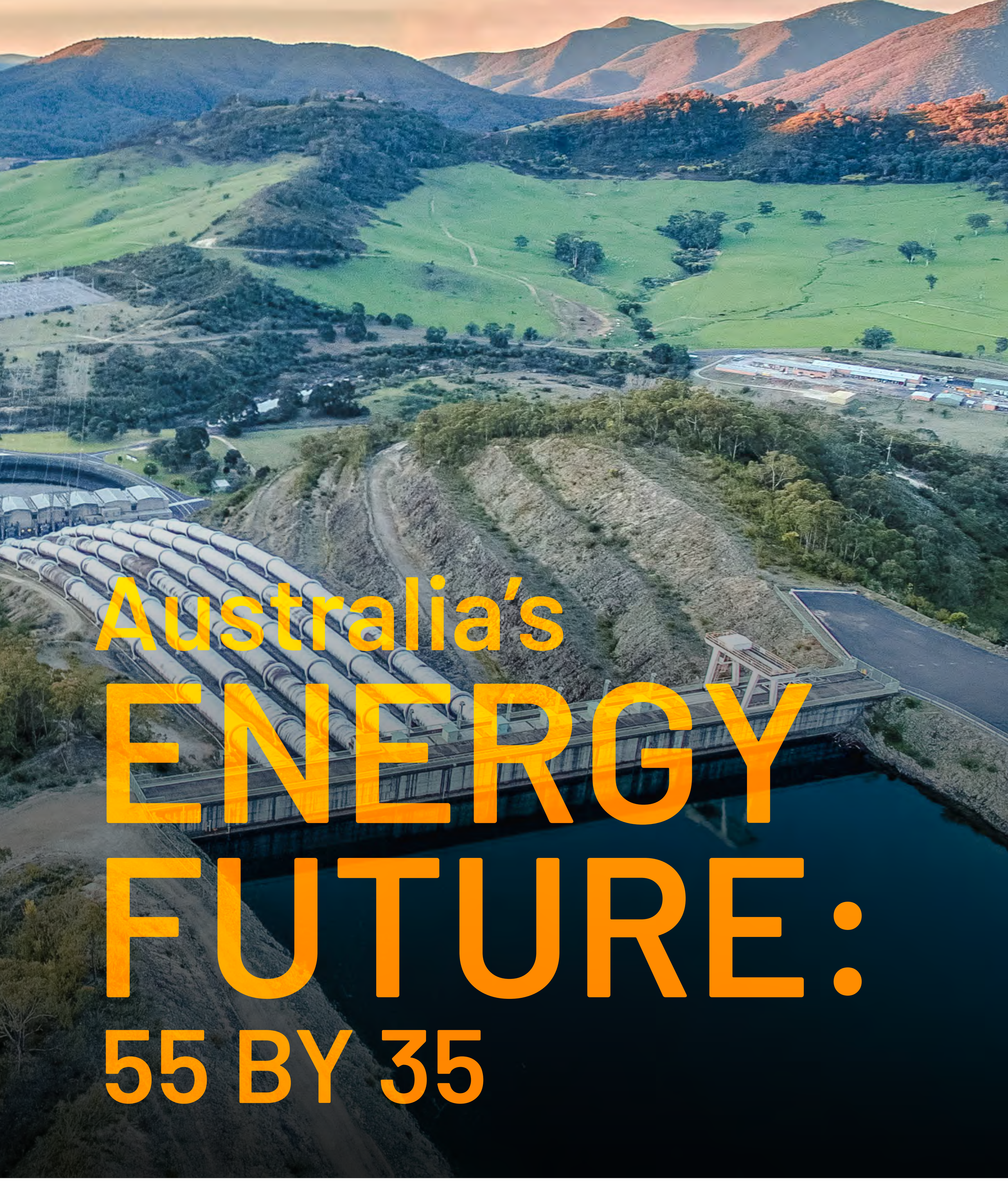

Australia's ENERGY FUTURE: 55 BY 35

Zero Emissions Dispatchability

AUSTRALIAN ENERGY COUNCIL

Executive Overview

The AEC has proposed an economy-wide interim emissions target of 55 per cent reduction on 2005 levels by 2035 as a milestone on the way to net zero. This paper is one in a series of papers exploring the implications of the 55 by 35 target. The electricity sector will play an important and substantial role in meeting the interim target. As a result, this paper focuses on the need for zero emissions dispatchable plant to complement the growth of renewable energy and the retirement of existing dispatchable coal and gas generation.

While the growth of renewables will deliver low cost energy in the middle of the day and at other periods when the wind blows strongly, it won't deliver all the power the system needs to meet demand at all times. In particular there are periods in winter where there is no solar output (because it's dark) and there are low winds. At these times we may need up to 16 hours of dispatchable plant, for several nights in a row. This is likely to be provided by a mix of short duration and long duration storage and thermal plants using low emission fuels. Specific technologies include lithium-ion batteries, pumped and conventional hydro, and peaking plants running on gas or biomass. Hydrogen powered plants may also play a role eventually. Other technologies are possible but unlikely in the period to 2035, and an appendix explains why.

Modelling exercises, such as the Australian Energy Market Operator's (AEMO) integrated system plan (ISP), and the Western Australian Government's whole of system plan can give us an insight into how much dispatchable capacity is required. Like any modelling, they should not be taken as a definitive answer. Given we can't forecast precisely how much dispatchable capacity we need, the most efficient way to deliver this will be to let market signals do the work. In the National Electricity Market (NEM), the energy-only market in tandem with the contract market is the main signal, and so the reliability settings need to continue to provide effective incentives as the market transitions. Already, they have been supplemented with a Retailer Reliability Obligation and an expanded emergency reserve. By contrast, in the WA's Wholesale Electricity Market (WEM), it is the capacity mechanism that drives new investment. Direct government support is another way to elicit investment but is unlikely to be an efficient approach. Whatever mechanisms are used, it is important that policymakers continue to monitor their effectiveness.

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Introduction

The Australian Energy Council (AEC) published its Net Zero by 2050 policy in June 2020. That policy has since been adopted by Australia, and focus has turned to interim targets to set the economy on a realistic pathway to this ambition. An interim target should be aspirational yet achievable, and consistent with the overall goal of net zero by 2050. An economy-wide target is more flexible and efficient than purely sectoral targets. With these factors in mind, the AEC has proposed an interim economy-wide reduction target of 55 per cent from 2005 levels by 2035 ("55 by 35").

This paper is one in a series exploring the implications of the 55 by 35 target. The electricity sector will play an important/substantial role in reducing Australia's emissions and meeting net-zero. As a result, this paper focuses on the need for zero emissions dispatchable plant to complement the growth of renewable energy and the retirement of existing dispatchable coal and gas generation.

What is zero emissions dis-patchable plant?

Zero emissions dispatchable plant has two characteristics. Dispatchable plant is plant that can be relied upon to run when called on to do so. Its availability is not weather dependent. Ideally it has fast ramping capabilities; that is, it can increase its output quickly. Wind and solar are not dispatchable. This includes offshore wind, which runs more frequently than onshore wind, but is still ultimately weather-dependent.

Zero emissions plant does not produce material amounts of greenhouse gases when it runs. Unabated coal, gas and oil-powered plants are not zero emissions. Technically, a target of 55 by 35 allows for some emissions in the electricity sector, but it is a staging post towards net zero, and power plants are designed to run for decades, so it's important that new plant has an emissions intensity close to zero (there is likely to be some legacy fossil fuel plant still running in 2035). Some residual emissions may be offset to achieve net zero, but this should not be seen as a substitute for emissions reduction in the sector.

The need for dispatchable plant

Electricity systems will always need some dispatchable plant even under high levels of renewables because wind and solar cannot be guaranteed to meet demand for electricity every hour of the day, every day of the year. Renewables advocates sometimes argue that as more wind and solar gets built over a wider geographical area, their diversity of output will improve. In other words: "the sun is shining, or the wind is blowing somewhere". Evidence to date from the National Electricity Market (NEM) suggests this is not sufficiently the case.

Winter (June to August) is the most supply challenged season for large scale renewables, due to lower solar irradiation (which also impacts rooftop solar output). Figure 1 below looks at how well wind and solar complement each other. A correlation coefficient of 1 is perfect correlation (they always run together) and -1 is perfect negative correlation (one is on when the other is off and vice versa). A high negative coefficient indicates high diversity.

Figure 1 *Renewables correlation winter 2021*

	NSW WIND	NSW SOLAR	QLD SOLAR	QLD WIND	SA SOLAR	SA WIND	VIC SOLAR	VIC WIND	TAS WIND
NSW Wind	1								
NSW Solar	-0.15	1							
QLD Solar	-0.06	0.84	1						
QLD Wind	0.28	-0.34	-0.30	1					
SA Solar	-0.16	0.82	0.76	-0.34	1				
SA Wind	0.37	-0.15	-0.11	0.06	-0.22	1			
VIC Solar	-0.14	0.92	0.79	-0.32	0.83	-0.18	1		
VIC Wind	0.39	-0.03	-0.03	0.10	-0.10	0.60	-0.06	1	
TAS Wind	0.27	0.01	0.02	0.09	-0.03	0.12	-0.01	0.57	1

Level 14, 50 Market Street, Melbourne VIC 3000

Solar: solar correlation

In the winter of 2021, mainland NEM states observed highly positive solar correlations, although the coefficients are less than 1, even though the sun rises and sets at much the same time. That's because of increased cloud cover due to variation in weather patterns in different regions.

Wind: wind correlation

Each state's wind was slightly positively correlated with other interstate wind generation. So, the wind isn't always blowing somewhere.

Solar: wind correlation

There was some slight negative correlation between wind and solar in each state, ranging from minus 0.06 to minus 0.34. This reflects Australian weather patterns that lead to overnight wind. This slight negative correlation is somewhat useful, but nowhere near high enough to avoid the need for substantial firming generation capacity.

Building renewables out into new areas is unlikely to improve diversity significantly. The NEM is already one of the largest electricity grids in the world by geographical spread. Pushing the grid further west, even by hundreds of kilometres, only adds a few minutes of additional solar output in the evening. And the wind patterns are large enough that new Renewable Energy Zones (REZs) are unlikely to capture significantly different output profiles.

Dunkelflaute is the German word for "dark and still", or those times when the sun isn't shining, and the wind isn't blowing. As renewables grow to dominate power grids, keeping the lights on during Dunkelflaute periods when the renewables are off will be increasingly important. There is no clear definition of how little renewables need to be on to be Dunkelflaute. As Figure 2 below shows, capacity factors of the NEM's combined wind and solar fleet are rarely above 50 per cent and can dip below 10 per cent. This shows an indicative period in April 2021 where there was a period of a week when there was very low wind overnight. The data does not include rooftop solar, but the inclusion of rooftop solar capacity and output would not materially change the results, given its output is closely correlated with utility-scale PV.

Of key interest is the circled period late in the month. This was a week when there was little wind overnight (and – obviously – no solar), leading to a run of up to 16 hours with low renewables output. Using 15 per cent capacity factor as a benchmark, Figure 3 (over page) shows the number of consecutive hours of Dunkelflaute conditions on each day of April.

Figure 2 *Capacity factor of renewables in the NEM, April 2021*

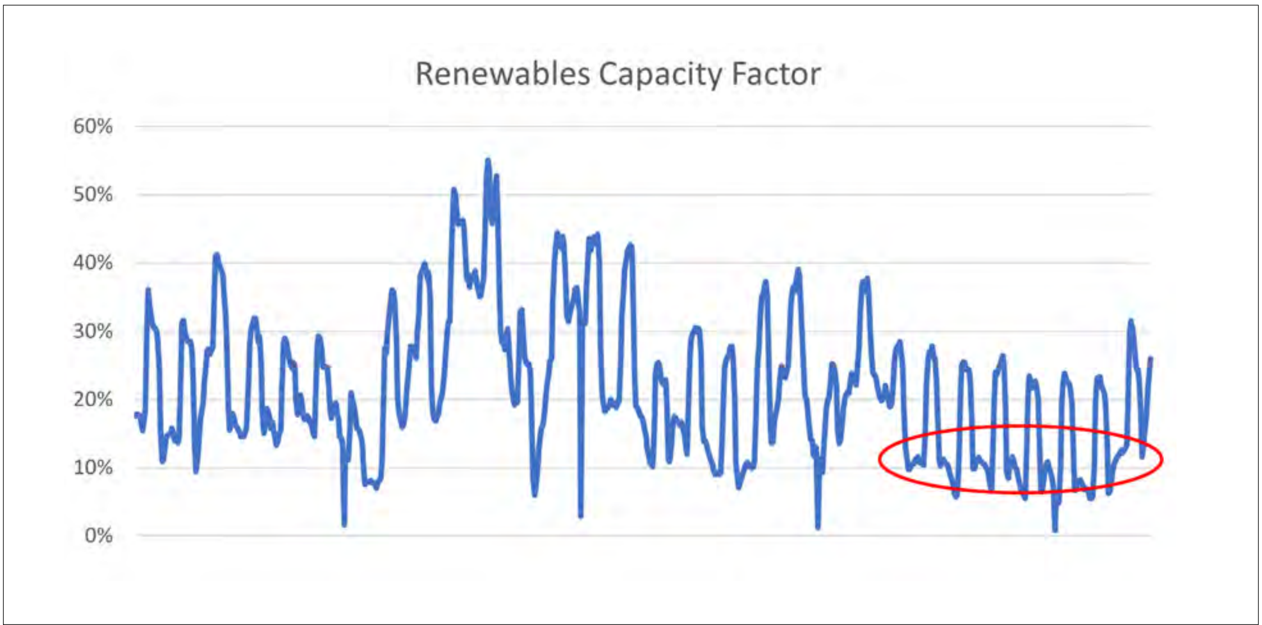
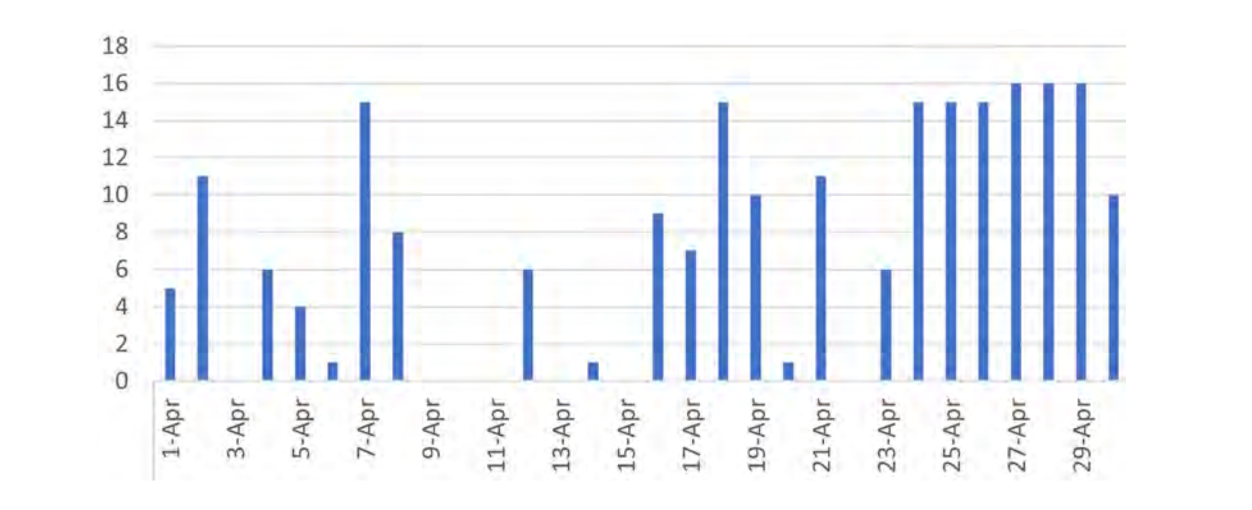


Figure 3 *Consecutive hours of renewables capacity below 15 per cent*



The point of these consecutive periods is that these are the ones that will need to be filled by storage and/or flexible but firm generation in a decarbonised NEM. Just building more wind and solar will not help meet demand in these periods, even if they are able to fully meet demand at other times.

Lithium-ion batteries are built to deliver two to four hours' worth of output before they are fully discharged. They are not going to be enough to fill 15-16 hour gaps. Plus, there may only be 8-9 hours of daylight to replenish before the next one. So, the NEM is going to need long-duration storage such as pumped hydro or flexible generation such as zero-emission gas turbines. Batteries will play a significant role in meeting short-term supply requirements and to provide other services, such as frequency control and network support, but are not a complete solution in themselves.

Similarly, demand response may play a similar role to lithium-ion batteries, but the nature of demand response is that it is unlikely to be sustainable for more than a few hours at a time.

While this analysis has focussed on the NEM, the same points are salient for WA's South-West Integrated System (SWIS). The SWIS is considerably smaller and so is even less likely to have highly diverse renewables output.

"100 per cent renewables" claims

Some jurisdictions and organisations claim that they operate on 100 per cent renewables. In most, if not all cases, this is not strictly true. It typically means that they have purchased renewable electricity contracts equal to the total quantity of electricity they consume. It's rare that they specifically seek to purchase contracts that match their consumption hour by hour (or for the NEM, for every five minute dispatch interval). This would be extremely complicated to manage and hard to do purely through renewables contracts. There may be a locational mismatch too. The ACT was one of the first jurisdictions to claim to be 100 per cent renewables. Several of the wind farms it sponsored to meet that claim are in Victoria or South Australia, some considerable distance from Canberra. The ACT, like other claimants, remains dependent on dispatchable power plants in order to meet their demand reliably. This is not to be critical of such initiatives, which have played an important role in underwriting renewable investment. But logically, if all consumers tried to go 100 per cent renewable in this way, it just wouldn't work, because the system demand and supply would be mismatched. As renewable integration in Australian grids deepens, organisations who certify 100 per cent renewable claims may need to consider including a time-matching dimension in their certification process.

Types of zero emissions dispatchable plant

The realistic options for providing zero emissions dispatchability divide into two basic types: energy storage plant and fuelled plant.

Energy storage plant uses electricity to store in some medium (chemical, physical) and then generates electricity from that medium. The most obvious examples currently deployed in Australia are battery storage (typically lithium ion) and pumped hydro. They are also the two plant types garnering the most investment (outside of renewables) at the current time.

Other potential storage options include compressed air, molten salts (typically in combination with solar thermal) and flow batteries.

Storage can be characterised by timeframe as well as technology type. AEMO distinguishes between five different types/durations of storage.

- **Distributed storage** – includes non-aggregated behind-the-meter battery installations designed to support the customer's own load
- **Coordinated Distributed Energy Resources (DER) storage** – includes behind-the-meter battery installations that are enabled and coordinated via Virtual Power Plant (VPP) arrangements. This category also includes EVs with Vehicle-to-Grid (V2G) capabilities.
- **Shallow storage** – includes grid-connected energy storage with durations less than four hours. The value of this category of storage is more for capacity, fast ramping and frequency control ancillary services (FCAS, not included in AEMO's modelling) than for its energy value.
- **Medium storage** – includes energy storage with durations between four and 12 hours (inclusive). The value of this category of storage is in its intra-day energy shifting capabilities, driven by the daily shape of energy consumption by consumers, and the diurnal solar generation pattern.
- **Deep storage** – includes energy storage with durations greater than 12 hours. The value of this category of storage is in covering Variable Renewable Energy (VRE) "droughts" (long periods of lower than expected VRE availability) and seasonal smoothing of energy over weeks or months[1].

At present, lithium-ion batteries are the main provider of shallow storage. It's possible that those and other battery chemistries could also provide medium storage. Deep storage is currently the preserve of pumped hydro and traditional hydro, with other potential deep storage options still at the development stage.

The global push to commercialise green hydrogen production and use cases presents some optimism that green hydrogen could provide an additional viable storage source (since green hydrogen is produced from electrolysis of water powered by renewable electricity, it is effectively a form of storage). Two new gas generators under consideration are being described as "hydrogen ready": Port Kembla and Tallawarra B. In principle, there should be low technological barriers to developing a gas turbine that can be powered entirely by hydrogen. In practice, there are no such generators yet deployed globally[2]. Additionally, green hydrogen is currently significantly more expensive than natural gas, noting that the Australian Government has a stretch goal to deliver significant cost reductions by 2030, as part of its technology roadmap. Nonetheless at the present time it is premature to assume that green hydrogen will be economic by 2035. The opportunities and challenges of the green hydrogen sector will be explored in more detail in a subsequent paper in this series.

Fuelled plant uses an energy source from outside the electricity system. There are a range of traditional examples, most obviously fossil-fuelled plants, albeit these are not zero emissions. The NEM also includes biomass, waste gas and hydro power plants.

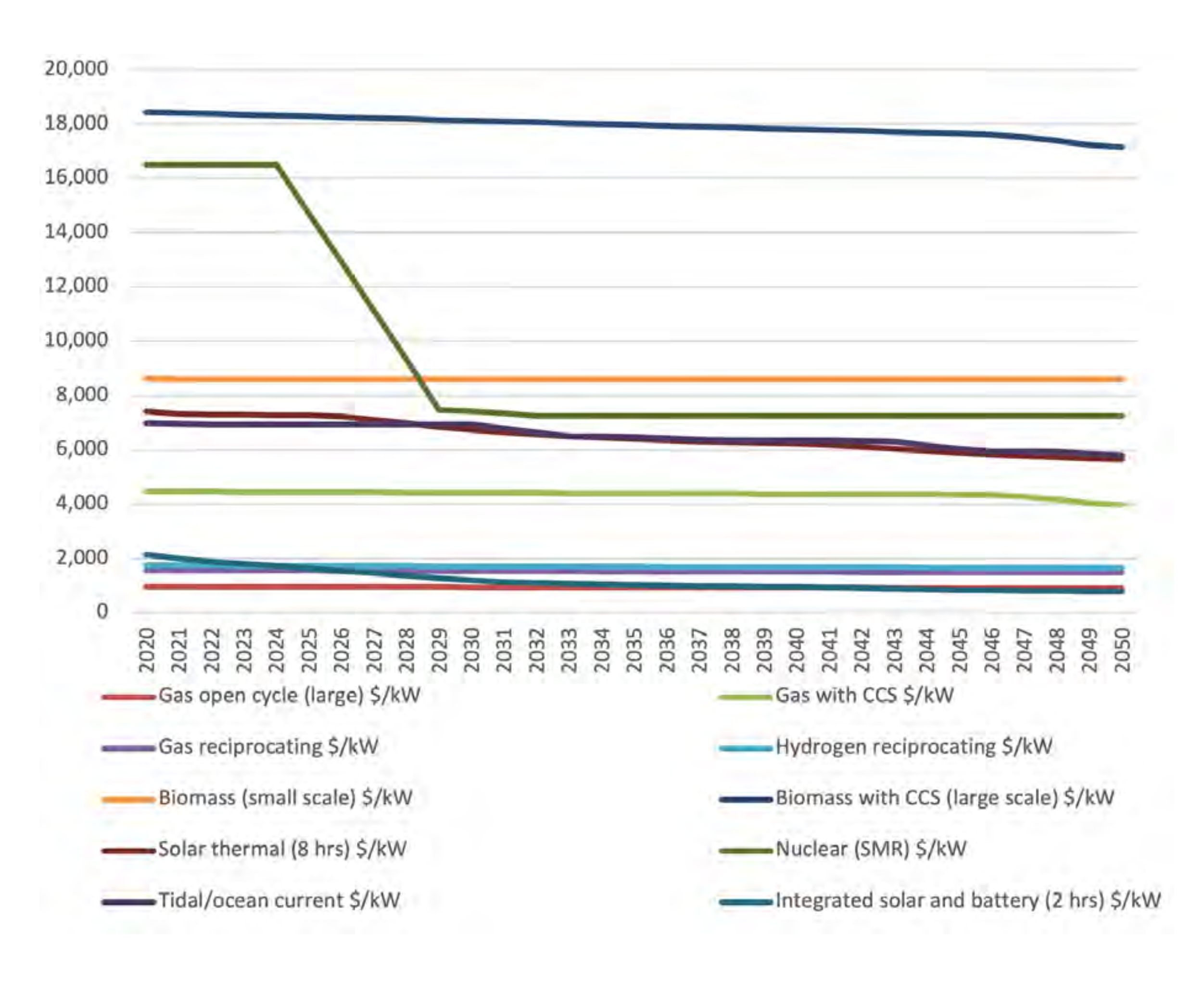
Hydro power plants come in multiple types. Along with pumped hydro storage, there is run-of-river hydro, which faces the risk of spill if its energy is not dispatched, and inter-annual storages, such as Gordon and Great Lake in Tasmania. These effectively store large volumes of water behind a dam and can smooth seasonal energy requirements. Hydro is vulnerable to extended droughts.

Most other potential examples are not mature technologies or face some specific barriers to deployment in Australia. Energy technologies like solar PV or lithium-ion batteries seem to have appeared abruptly and spread rapidly, but the reality is that this is the culmination of decades of research and development and limited deployment for niche use cases. Accordingly, claims by proponents of a particular technology that it is "just around the corner" should be treated with scepticism. This section is not about "picking winners" and determining ex ante which technologies will be deployed to deliver decarbonised electricity, but rather illustrating that technology deployment does not happen overnight and we should be prepared to rely largely on existing technologies that are already in or close to widespread deployment. However, for completeness, Appendix 1 considers a range of other technologies that are or have been proposed as playing a role in a future Australian low carbon electricity system.

Cost comparisons should be treated as indicative – they can vary depending on the underlying assumptions and usually assume technology has matured. Where a technology has yet to be deployed in Australia, it is likely to incur additional costs for the first few plants installed before reaching a mature cost level. Cost comparisons provide an illustration of why some conceptually attractive technologies are not being more widely deployed.

1 Draft Integrated System plan p49, AEMO, December 2021
2 The Hyflex project in Europe appears to be the most advanced demonstration project: http://www.hyflexpower.eu/about/

Figure 4 *Capital cost estimates of various low/zero emission technologies, $/kW*



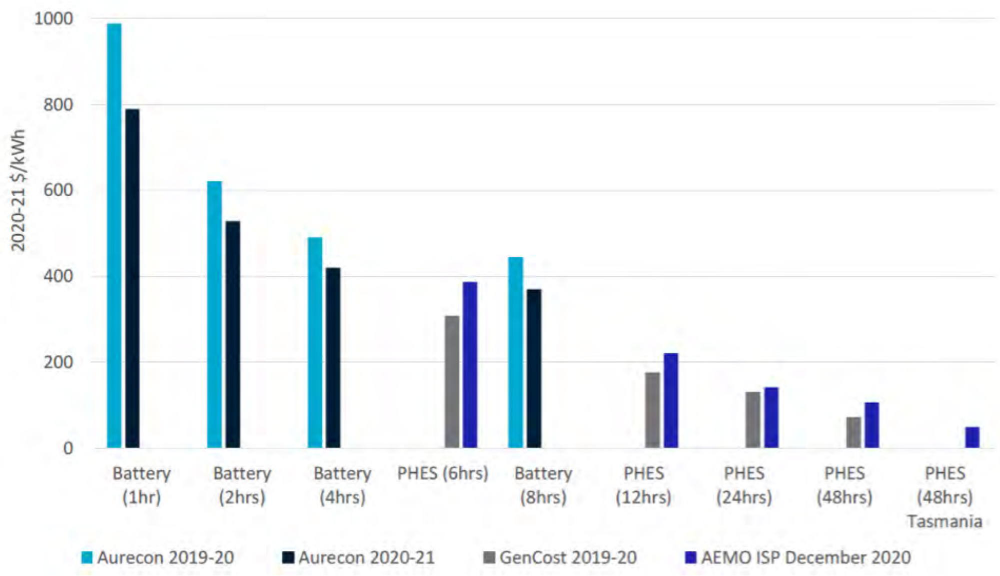
Source: GenCost project data, CSIRO, 2021

As can be seen in Figure 4: Capital cost estimates of various low/zero emission technologies above, gas peakers (open cycle or reciprocating engine), hydrogen peakers and solar plus battery are significantly lower capital cost than the other options across the period to 2030. Gas and hydrogen peakers will also have a fuel cost (and gas may have a compliance or offset cost for its emissions), however, if they are only used periodically, this will not be high enough to make them more expensive than the other technologies. Solar plus battery is thus in principle the cheapest to install, but 2 hours storage is not sufficient as the only dispatchable technology, as explained above.

The cost analysis in Figure 4 above does not include the pure storage technologies: batteries and pumped hydro. These are hard to directly compare to generation technologies, as their "fuel" costs are based on the cost of the electricity at the time they use it to charge, as well as their round-trip efficiency. The relative costs of these depends on the metric. Batteries have lower capital costs, and better round-trip efficiency, but can store less energy per KWh. So, they are highly cost-competitive for short duration needs, but pumped hydro has an advantage for longer duration, because it can deliver a large volume of energy. A comparison of the pure storage technologies on a $/kWh total cost basis is shown in Figure 5 below.

There is also benefit – up to a point, depending on relative technology costs – in having some diversity of underlying fuel sources. A "closed loop" electricity system comprised only of weather dependent renewables (solar, wind, hydro) plus various storage options would be vulnerable to extended extreme weather patterns such as droughts or Dunkelflaute because it would have no other way to inject energy into a fuel system.

Figure 5 *Capital costs of storage technologies in $/kWh (total cost basis)*



Source: GenCost 2020-21, CSIRO, June 2021

Noting the relative costs and maturity of fuelled plant, and the value of diversity, Australia should be prepared to contemplate the ongoing use of some fossil fuel plant. In its draft ISP, AEMO notes that "gas-fired generation will play a crucial role as significant coal generation retires, both to help manage extended periods of low VRE output and to provide power system services to provide grid security and stability"[3]. Gas peakers are clearly not carbon neutral, unless the gas comes from waste gas sources, such as landfill, biogas, or its upgraded form biomethane. However, in situations where they are used infrequently, their overall emissions are relatively small, and it may be possible to offset these emissions through the carbon market. There is likely to be competition from other hard-to-abate sectors for the limited supply of offsets as the country moves closer to net zero, so offsets are not suitable for wide-scale use in the electricity sector, but they may have a role to play.

Waste gas already provides a modest contribution towards Australia's electricity supply. The supply of waste gas or biogas is limited by the level of feedstock available, which in turn is driven by the activity that produces the gas as a by-product. The Australian Government's Bioenergy Roadmap explores ways that the supply of feedstock could be increased. A consistent stream of waste gas, such as from landfills, gives the produced electricity baseload characteristics which may be useful for grid security and reliability.

How much dispatchable plant is required?

There is no definitive answer to the question of how much plant is required to ensure reliability. There are a range of factors that will determine the amount required. These include:

- Demand – total demand and load profiles
- Level of reliability sought
- Patterns of renewables output – influenced by weather patterns
- The development of the transmission network
- How close resources operating under uncertainty can get to fully optimised dispatch

AEMO's draft ISP, released late 2021, provides an indication of the quantum of dispatchable plant required for the NEM. In its Step Change scenario, which it considers to be the most likely scenario, 61GW is required by 2050. AEMO's modelling suggests this could be made up of 45GW/620GWh of dispatchable storage capacity, 7GW of existing hydro and 9GW of gas-fired generation. Storage is a mix of new pumped hydro (specifically Snowy 2.0, which is expected to provide around half the required stored

3 Draft Integrated System plan p29, AEMO, December 2021

energy), other deep storage, medium/shallow storage and coordinated distributed storage. By contrast, there is 43GW of dispatchable capacity in today's NEM.

However, this is only an indication of the required capacity. The purpose of the ISP is to determine what is likely to be the most cost-effective build-out of transmission under a set of realistic scenarios. The plant mix in the scenarios is driven by the underlying assumptions, including on the relative cost of different generation and storage options into the future. The scenarios do not cover all eventualities, and the underlying assumptions may turn out not to hold. None of this is to criticise AEMO or the ISP scenarios, merely to point out the inherent uncertainties.

There are a number of uncertainties and factors that may affect the required dispatchable capacity. Some of these are explored below.

Demand may be different from AEMO's assumptions.

AEMO's demand traces are developed based on a set of assumptions. These are based on taking historical demand trends and correlation to temperatures, population, income and other variables and then projecting those forwards. These are then overlaid with projections for new sources of demand (or demand reduction) including EV charging, a renewable hydrogen industry and continuing take-up of distributed energy resources (DER, which includes rooftop PV and customer-owned batteries). There is a lot of underlying uncertainty, especially around new sources of demand and how customers will use their DER.

Society may demand a higher level of reliability than assumed by AEMO

It's not economically practicable to build an electricity system that can fully meet demand under all possible outcomes. So, systems are built to meet reliability standards – a maximum level of outages or unserved load that is considered socially tolerable. Historically the NEM has operated to a reliability standard of 0.002 per cent unserved energy per year. In practice it has usually delivered full reliability (this metric does not include periodic network outages). AEMO is required to use this standard as a reference when developing the ISP. It does so using minimum capacity reserve levels for each region as a proxy for reliability[4].

However, energy ministers recently applied an interim reliability measure of 0.0006 per cent per year, subject to review in 2023. If this or some other, tighter standard was applied in the future, reflecting society's increased expectation of reliable supply, then more capacity would be required to ensure it (in the ISP this would manifest through higher assumed minimum reserve capacity levels). Given electrification of other energy needs (transport, heat) is envisaged as a major trend in decarbonisation, there is a high chance that society will require a tightening of reliability as we become progressively more dependent on electricity systems. For context, it's worth noting that the great majority of customer outages are due to network issues rather than unserved energy.

The system may need to be resilient to more extreme weather than assumed by AEMO

AEMO evaluates both demand and supply in the ISP using historical weather patterns. Hot and cold days lead to demand for heating and cooling. Renewables are of course weather-driven. Hot days can reduce the efficiency of electricity systems. Extended drought can cause energy constraints at hydro systems. Climate change may result in different weather and climate patterns in the future. AEMO can and does seek to adjust for this, but it can't know for sure how these changes will manifest. Higher peak demand – especially in winter when there is lower solar output, hydro drought, and wind drought could all result in a requirement for more dispatchable capacity.

AEMO acknowledges in the ISP that it does not incorporate all possible weather outcomes and impacts. For the final ISP it will model some more extreme scenarios, including:

- coincident heatwaves and bushfires, impacting consumer demand and power system capability;
- extreme wind or solar droughts, possibly resulting in extremely low energy availability; and
- extreme storm or cyclone risks that have the potential to damage generation and transmission infrastructure.

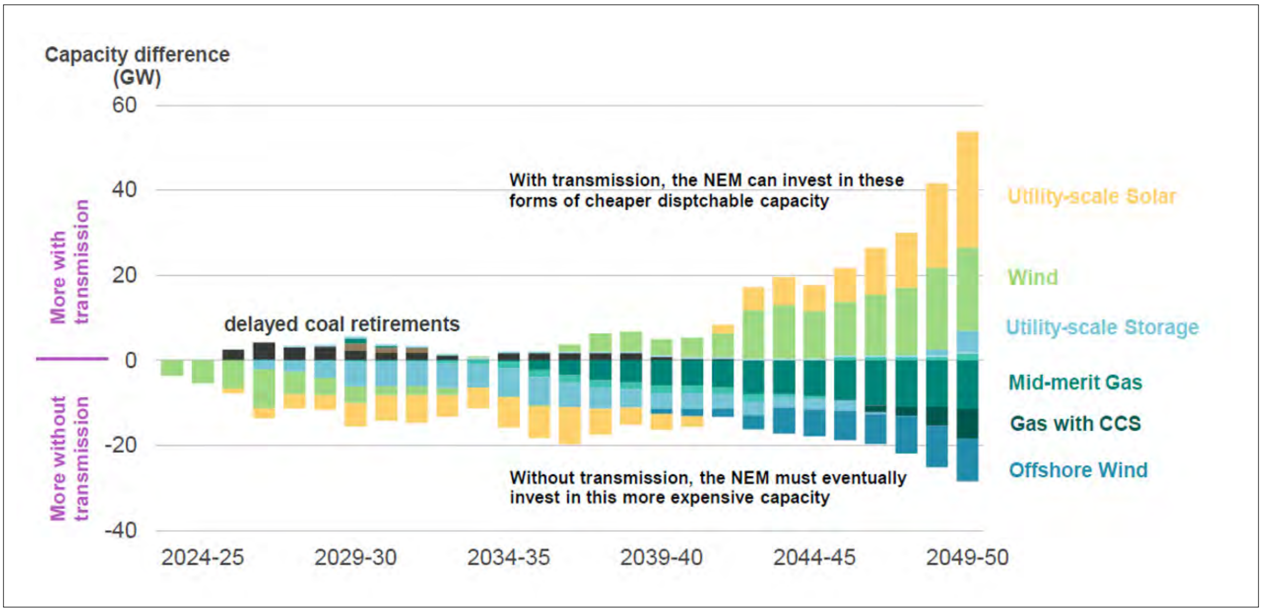
The results of this exercise may indicate more dispatchable capacity is required to achieve the desired level of resilience in the electricity system.

Not all the transmission in the ISP gets built

Transmission extensions are a significant undertaking, and while many of the projects in the ISP are likely to get built (unless our expectations of the NEM change fundamentally), there may be barriers. These are major construction projects and may face social licence issues, like any other big infrastructure proposal, including large-

4 2021 ISP methodology p40, AEMO, August 2021

Figure 6 *Incremental capacity depending on level of transmission build-out*



Source: AEMO Draft ISP

scale generation and storage. AEMO notes that if ISP projects are not completed on the time frames it expects, then more generation is required, much of which will need to be dispatchable.

The reverse is not true, however. Additional transmission beyond the optimal level has diminishing returns in terms of avoidable generation investment. Even in some cases where parts of the system have periods of surplus renewables, it may be more efficient to build extra dispatchable capacity than to build extra transmission. Ultimately, transmission only moves energy around, so there will always need to be dispatchable capacity to generate the electrons.

Optimisation is unlikely in the real world

Because AEMO knows what its own assumptions are about weather patterns and demand profiles, and because the ISP modelling is a least-cost exercise, it optimises the operation of storage in its modelling. In practice, operators of storage do not know the future and are optimising to market signals. They may also be providing multiple services. For example, the Victorian Big Battery is partly underwritten by a network services contract. This means that its full capacity is not available for the energy market. Accordingly, storage operators may find they do not have a fully charged asset at times when dispatchable capacity is sought. While this challenge can be somewhat alleviated through the presence of longer-duration storage that is more likely to be available at times of system stress, more capacity in total may be required to ensure reliability.

These limitations of the modelling do not undermine AEMO's conclusions, given that the primary purpose of the ISP is to determine what is likely to be an efficient transmission investment program, not to determine exactly how much dispatchable capacity is required or what the mix of resources will be. In practice decisions about dispatchable capacity investment (and retirement of older capacity) will be taken progressively as the future reveals itself. How this investment is supported is covered in the next section of the paper.

Western Australia will likely face a similar set of uncertainties as it transitions. The WA Government's 2020 whole of system plan (WoSP) runs to 2040, rather than 2050 as in the ISP and is not predicated on such a significant churn in generation. Some of the existing fossil-fuelled plant is displaced by growing renewables and under some scenarios a modest amount of new investment in gas is required. However, if technology, customer choice, or emissions reduction policies accelerate the energy transition in WA, then higher-emissions plant will need to be replaced by greater amounts of zero emissions dispatchable capacity.

AUSTRALIAN ENERGY COUNCIL

Supporting dispatchable capacity investment

At present, both the NEM and the WEM use market signals to determine the efficient dispatch of resources. They have quite different approaches to how investment is supported, however, and in the case of the NEM, that approach continues to evolve. Investment mechanisms can be considered along a continuum of decentralised decision-making to centralised decision making.

1. The NEM's energy-only market

The NEM is an example of an energy-only market. The wholesale market design does not incorporate specific payments for capacity. Instead, generators (and storage) are paid for the energy provided when they are dispatched, and they are only dispatched if they bid at or below the market clearing price for each dispatch interval. Given this, and given the potential volatility in prices, which can vary between $-1,000/MWh to $15,100/MWh, it is in generators' (and consumers') interests to hedge these prices. Accordingly, a secondary market has grown up alongside the energy market to provide these hedging instruments. These have the effect of converting volatile spot prices into a consistent set of payments over time, and thus function as payments for capacity.

The two most basic hedging instruments are the swap, and the cap. Swap contracts effectively fix the market price over a period of a quarter or a year, for 24 hours a day or for a peak period. This provides revenue certainty for the generator and cost certainty for the customer (usually a retailer on behalf of their customers). They are well suited to generation that runs all the time, such as coal plant.

The cap contract is likely to grow in importance as renewable output grows to the point where it can provide 100 per cent of wholesale energy at times, and dispatchable generation is only needed periodically. A cap contract pays the generator a consistent income for the period covered and reimburses the customer for prices in excess of a given threshold, typically $300/MWh. So, there is a very strong incentive for the generator to be dispatched when the price exceeds $300/MWh, as the contract means that it, rather than the customer, is exposed to very high prices. So, the cap contract is well suited to generation that only runs when high prices signal extra generation is needed, such as gas peakers.

There are other types of contracts, and the market will continue to evolve, but the principle remains the same: mutual interest in hedging between generator and customer results in a decentralised capacity market. The market creates incentives for the customer to be conservative in estimating the load they have to cover and for the generator to be confident it can defend the contract as required. But there is no single formal determination of how much capacity is required or how to define that capacity (e.g., for how long must it be able to run continuously without recharging).

A potential drawback with the energy-only market is the "missing money" problem. This is the hypothesis that the market may not value capacity enough in all years to meet reliability expectations, primarily due to the existence of a regulated price cap in all energy-only markets. The relative insensitivity of demand to short-term price signals, and the inability to add new capacity in the short term, leads to concerns that the market may occasionally settle at an almost infinite price, when capacity is most scarce. So, an artificial cap is imposed, potentially both for an individual dispatch interval and at a cumulative level over multiple periods (in the NEM this is equal to 7 ½ hours of the price cap occurring in a rolling seven days, after which prices are administered for seven days). This in turn reduces the efficient price of hedge contracts.

The NEM's price cap may be amongst the highest in the world, but on other metrics it may be too low. It is lower than the estimated value of customer reliability, which the Australian Energy Regulator (AER) has calculated at around $24,000/MWh for residential customers and $38-64,000 for business customers.[5] It is also lower than some modelled estimates of the value necessary to attract sufficient investment in a high renewables system.

2. Enhancing NEM capacity price signals

To date, rather than increasing the price cap, policymakers have used different tools to address concerns about the market delivering sufficient dispatchable capacity. One of these is in-market, while the other is out-of-market.

Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) was introduced to the NEM in 2019. The conditions for the RRO to be invoked are for AEMO to identify a reliability gap three years in advance in any jurisdiction in its Electricity Statement of Opportunities (ESOO) released by August 31 each year. If the market response to the RRO is not adequate a year out from an expected reliability event, retailers will be required to disclose their contract positions to the regulator (AER). Those who are insufficiently covered will be required

5 Values of customer reliability review – Final decision, AER, December 2019

to contribute to the costs of emergency procurement through the Reliability and Emergency Reserve Trader (RERT) mechanism. Civil penalties may also apply.

The RRO has not yet been through a full compliance cycle to see how it would work. The first few occasions on which a reliability gap was declared, the gap was subsequently cancelled. Nonetheless, it has been subject to amendment on multiple occasions, including the introduction of a Ministerial Trigger and the ability for AEMO to call a reliability gap one year out. The Energy Security Board (ESB) has indicated that the RRO is likely to form the basis of a proposed capacity mechanism (detailed design has yet to be carried out).

The RRO represents a hybrid between a fully decentralised and a fully centralised approach. It's decentralised in that individual participants are still the ones striking deals for capacity through the contract market. It's centralised in that the required level of contracting is effectively determined by AEMO through its forecasting processes and the AER has to determine that the contracts used by retailers are appropriate contracts.

Emergency or operating reserves

The RERT was originally intended as a temporary backstop when it was introduced at market start. After multiple extensions it was made a permanent feature of the NEM in 2016 despite not having been used. AEMO used it for the first time in 2017/18 following the closure of Hazelwood power station. AEMO operates the RERT procurement and activation processes under guidelines developed by the Reliability Panel at times when it considers the market will not deliver sufficient supply to maintain reliability. So, it contracts with non-market providers (typically small generators or demand response from large customers) to provide temporary supply.

When used, the RERT typically costs more per MWh procured than the market price cap, but less than the value of customer reliability. The scope of the RERT was extended as a result of the increased interim reliability measure. The ESB is considering introducing an ongoing Operating Reserve, which would work on similar lines to the RERT. Other energy-only markets, such as Texas have a similar mechanism.

While it is a fully centralised approach, the use of emergency/operating reserves is typically only for small amounts of supply at infrequent times of supply/demand balance. As such it is less material in cost and market impact than a full capacity market. Nonetheless it is telling that the consultants asked to report on the costs and benefits of the interim reliability reserve explicitly noted that "lifting the market price cap to a level consistent with the value that consumers place on reliability [i.e., in the order of $40-45,000/MWh]…is the most economically efficient approach as it allows the market to naturally clear based on price".[6]

3. Capacity market/capacity mechanism

Many electricity markets around the world, including the WEM, have an explicit, centralised capacity mechanism. Whether it represents a market or not depends on how the price is determined. Some capacity mechanisms like that of the PJM in the US (the world's largest wholesale electricity market) are based on a reverse auction with supply resources (generators, storage, demand response). Others, like the WEM, have an administered cost curve. The logic behind using some sort of capacity payment is to put an explicit value, and certainty, on getting new generation built.

A concern with capacity markets is that they will end up costing more, because the quantity of capacity is prescribed directly or indirectly. This tips the design more towards central planning, where the design of the capacity payments ends up predicting the design and cost of the system. There will always be a tendency for policymakers to favour designs that over-subscribe capacity, because the political consequences (higher cost) are more bearable than under-subscribing (blackouts). Note also that any capacity market design that only determined capacity payments annually (as many of them do) does not offer sufficient long-term revenue certainty.

As the role of storage grows, an additional issue with capacity markets is that there is a binary decision about how long a resource has to be able to dispatch for to qualify for payments. While the Dunkelflaute analysis above indicated that there are likely to be 16-hour periods of low renewables in still winter conditions, this doesn't mean that all capacity needs to be able to provide 16 hours duration. The efficient mix is likely to include some that can produce for 16 hours, but also some that only runs for one, two or four hours (these are typical durations for lithium-ion batteries, for example), providing it's cheaper to do so than long-duration storage. In a decentralised market, participants are likely to seek out the cheapest mix, but a centralised definition of capacity has to err on one side or the other. If it only rewards long-duration storage, it may incentivise an inefficient mix, because short-duration storage cannot access capacity payments, and capacity

6 ACIL Allen, Reliability standard – economic analysis to support review, March 2020

markets typically have a much lower energy price cap, so energy arbitrage opportunities are curtailed. Some short duration storage may still get built if it can earn enough in other markets, such as ancillary services or network support. If it rewards shorter-duration storage, then this may dominate the capacity auction (if it is cheaper on a per MWh basis) and there is a risk of not being able to meet demand during longer duration renewables droughts.

Of course, this could be mitigated by offering multiple types of capacity contracts for different duration, but this then becomes very complex and is still not guaranteed to deliver an efficient mix.

4. Government underwriting

The AEC and its members have long supported market solutions to delivering reliability. However, the level of government intervention in wholesale markets is hard to ignore. Continuing subsidies or other support for renewables is likely to exacerbate the missing money issue in the NEM, and thus runs the risk that there are insufficient market revenues for the necessary new investment in dispatchable plant. Some government schemes target dispatchability, such as the Federal Government's Underwriting New Generation Investment scheme, and elements of the NSW Government's Electricity Infrastructure Roadmap. Nonetheless, the NEM is a single system, and different policies on supporting investment from up to seven different governments inevitably lacks co-ordination and consistency.

Conclusion

This paper has established the need for adequate dispatchable generation to complement wind and solar. The need for this generation will be particularly acute in periods of low wind during winter nights. Storage technologies such as batteries and pumped hydro will play an important role, but system resilience will be enhanced by having some plant fuelled by an external energy source. However, the journey to net zero will increasingly constrain the type of fuel that can meet those needs.

We can't forecast precisely how much dispatchable capacity we need, so the most efficient way to deliver this will be to let market signals do the work. This makes it important to regularly check that we have the right market signals in place. There is a perennial debate among electricity market experts on the best type of market mechanism to elicit the necessary investment and this paper does not attempt to resolve them. The key is that whatever mechanisms we do have need to be effective and efficient so that customers can have confidence they are being supplied reliable electricity at the lowest cost.

Appendix 1: Other technologies

The cost comparison in Figure 4 above included several types of generation that have yet to be deployed (except for the odd small pilot plant) in Australia. These plant types and the challenges they face in delivering cost effective power are explained further below. The point is not to suggest these plants can never play a role in Australia's energy systems, but that there is little prospect of them making a material contribution by 2035.

Past electricity sector modelling often assumed that zero emissions dispatchability would largely be provided by a combination of three technologies (over and above existing hydro plant): nuclear, geothermal and fossil fuelled plant with carbon capture and storage (CCS). At present none of these look likely candidates for the period to 2035.

Nuclear

Nuclear power is still illegal in Australia. Even if it wasn't, setting up the regulatory framework would take several years. Large-scale nuclear projects are costly and take a long time to build. The UK recently embarked on a new nuclear plant at Hinkley Point, its first in over 20 years. The planning for this power plant began over a decade ago, with agreement struck with the plant developer, EDF in 2013. The final investment decision and the start of construction took place in the second half of 2016. It is currently expected to be fully commissioned in June 2026. On these timeframes, Australia is already too late if it wanted an operational nuclear plant by 2035. The cost, timeframes and relative inflexibility of nuclear could be somewhat addressed by the development of small modular reactors (SMR). The US Department of Energy has supported R&D into several such prototypes. But first commercial deployment of these is targeted at the end of this decade, so these, too, are unlikely to be part of the mix by 2035.

Geothermal

Geothermal energy is concentrated in a few countries where there is good quality heat resource near the surface such as New Zealand, the Philippines, and the US (California). Even in these places, it is usually a modest proportion of the overall plant mix. Australia's high quality heat resource is much deeper underground and concentrated in central Australia at some distance from major load centres. A decade ago, there was optimism that technological development would support the ability to cost-effectively exploit these deep resources. Geodynamics successfully drilled a 5km well and ran a 1MW pilot plant for several months. But the technology was unable to move to commercial large-scale deployment.

Carbon capture and storage

Carbon capture and storage (CCS) has, likewise, been under development for many years. An oilfield off the Norwegian coast, Sleipner, has successfully captured and sequestered its waste CO_2 for 20 years. However, its deployment in the power sector has yet to move beyond one or two demonstration plants (including at Callide A in Queensland). Of the two plants in commercial operation, one stopped capturing the CO_2 in 2020 because it became economically unviable (the CO_2 was used for enhanced oil recovery at a nearby oilfield until the oil price crash of early 2020). Widespread commercial use in power generation appears unlikely at this stage.

This is sometimes used to write-off the concept of CCS altogether. However, CCS may yet play a role in other, harder-to-abate sectors such as cement, if large scale fossil-free alternatives prove too difficult to deploy cost effectively.

In addition to those three plant types, CSIRO is also tracking costs of two further plant types: tidal/ocean current power and solar thermal.

Tidal/ocean current power

Power plants run on tidal energy come in two forms:

- Tidal range technologies harvest the potential energy created by the height difference between high and low tides. Barrages (dams) harvest tidal energy from different ranges.
- Tidal stream (or current) technologies capture the kinetic energy of currents flowing in and out of tidal areas (such as seashores). Tidal stream devices operate in arrays, similar to wind turbines.

Both types remain in the demonstration and development phase globally. While there has been a utility scale tidal barrage plant in France for several decades, there have been few built since and mostly at a smaller scale.

Solar thermal power

Solar thermal power suffers because it is in direct competition with solar PV but has been unable to match the latter's cost declines. There are a few different configurations of solar thermal power but essentially, they all use mirrors to focus the sun's power and concentrate it so it can turn water into steam. The steam can then be used to either drive a turbine or the heat can be stored in a suitable medium (such as molten salts) until required. Storing energy as heat in this way works for diurnal storage where the heat only needs to be retained for a matter of hours, but not seasonally.

Solar thermal power has been deployed in only a few places around the world, such as Spain, California and Morocco. This is typically the result of targeted policy support, and it's unlikely that there are any subsidy-free examples. Some of the largest plant has suffered reliability issues, usually connected to the steam process or the salt storage tanks.

ARENA is supporting a demonstration project in Victoria. Unlike international examples, this is a solar PV plant, which uses the heat as a by-product for storage purposes.

As the need for/value of medium-duration storage grows, it's possible solar thermal plus storage finds a niche that solar PV with batteries is less suited to. Solar thermal may also have an ongoing role in providing low level heat in non-electric applications, such as domestic hot water.

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