Firming technologies to reach 100% renewable energy production in Australia's National Electricity Market (NEM)

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Australia has committed to reducing its greenhouse gas emissions in a manner consistent with limiting anthropogenic climate change to no more than 2 degrees Celsius. One of the ways in which this commitment is being realised is through a shift towards variable renewable energy (VRE) within Australia's National Electricity Market (NEM). Substituting existing dispatchable thermal plant with VRE requires consideration of long-term energy resource adequacy given the unpredictability of solar and wind resources. While pumped hydro and battery storage are key technologies for addressing short-term mismatches between resource availability and demand, they may be unable to cost effectively address 'energy droughts'. In this article, we present a time sequential solver model of the NEM and an optimal firming technology plant mix to allow the system to be supplied by 100% VRE. Our conclusion is that some form of fuel-based technology (most likely hydrogen) will probably be required. This has important implications for Australian energy policy.

Keywords: energy storage; electricity markets; energy market modelling
JEL Codes: D40; D20; D22; L11

1. Introduction

Australia has committed to reduce greenhouse gas emissions in a manner consistent with limiting anthropogenic climate change to no more than 2 degrees Celsius with an aspiration to limit warming to 1.5 degrees Celsius (Meinshausen et al, 2021). These commitments imply that Australia will need to set a 'carbon budget'. When considered as a linear series of annual emissions reductions, the commitments imply a 50% and 75% reduction on 2005 emission levels by 2030 to achieve the 2 and 1.5 degrees outcomes respectively (Meinshausen et al, 2021). Both these commitments are significantly greater than the current Commonwealth Government target of 26-28% by 2030. It is therefore reasonable to presume that future emission reduction targets are likely to be more stringent, with international political pressure to 'ratchet up' commitments by the Australian Government very likely.

The electricity system is now seen as 'low-hanging fruit' for reducing emissions to meet Australia's carbon budget. Nelson, Gilmore, and Nolan (2021) note that around 60% of Australia's emissions reductions to date have been through the deployment of renewable energy within the Australian electricity system. Furthermore, it is now widely accepted that the cheapest technology for producing electricity is renewables (wind and solar) (see Graham et al, 2021; Dodd and Nelson, 2019), thereby facilitating a relatively cost effective more rapid depreciation of the existing system and investment in its replacement.

To keep the electricity system stable, it is necessary for a series of engineering constraints to be met. These include meeting prescribed levels or targets for system frequency, inertia and system strength. Furthermore, it is necessary for electricity demand to be met in real time by dispatchable supply due to its differential spatial and temporal value. Australian researchers have noted that absent low-cost energy storage, there are limits on the penetration of VRE due to the 'cannibalisation' of market

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revenues and impacts on system security and hedge markets (see Simshauser, 2018; Marshmann et al, 2019).

Given the variability of VRE supply due to its weather dependency, it is necessary to deploy energy storage to allow for electricity demand to be met continuously. Most existing studies of high penetration VRE electricity systems have focused on short-term mismatches between resource availability and demand which are well served by deployment of batteries and pumped hydro. Much less has been quantified about the need to deal with infrequent 'energy droughts' where there is a prolonged shortfall of solar and wind resources but continued use of electricity. It is unclear whether pumped hydro and batteries will be economic for addressing these 'energy droughts'.

Longer duration 'energy droughts' will occur in all electricity systems. The frequency of these events will differ by geography but it is inevitable that they will occur given the stochastic nature of weather events. It is therefore necessary to consider how electricity systems will maintain system reliability and security during 'energy droughts' when pumped hydro and battery storage resources are depleted and there is ongoing scarcity of instantaneous solar and wind resources. Technologies that are able to store larger amounts of 'fuel' are likely to be advantageous. These higher energy density options include current thermal technologies that may utilise growing volumes of alternative fuels in the future such as hydrogen or biodiesel.[1,2]

In this article, we present a model of Australia's National Electricity Market (NEM) to determine the optimal mix of firming technologies in a system where effectively all *energy* is generated by renewable resources (wind, solar and hydro). Rather than dissecting the (necessary) transition from today's system, we focus on identifying the end goal: how today's system would be rebuilt with the low emissions technologies assuming expected cost reductions have eventuated.

The model optimises across three forms of firming technologies: pumped hydro; batteries; and 'zero emission' open-cycle gas turbines (OCGT). Our hypothesis is that, even with very high fuel costs of \$50/GJ[3] to reflect the existing cost of sourcing 'zero-emissions' fuel such as hydrogen or biodiesel, OCGTs are deployed to address 'energy droughts' due to the storage limitations of batteries and pumped hydro. Section 2 provides a brief review of the literature of similar studies that have assessed high penetrations of VRE and the role of complementary storage technologies. Our methodology and data assumptions are documented in Section 3. The results of our modelling are presented in Section 4. Our policy recommendations and concluding remarks are presented in Sections 5 and 6 respectively.

2. Literature Review

Researchers have increasingly turned their attention to examining the feasibility of reaching 100% of electricity demand requirements coming from VRE. As noted by Steinke et al (2013, p. 826), 'Intermittent renewable power production from wind and sun requires significant backup generation to cover the power demand at all times. This holds even if wind and sun produce on average 100% of the required energy.' Therefore, it is necessary to consider complementary technologies that allow surplus energy to be stored (averaging or arbitraging over time) and interconnection to allow for greater special averaging or geographical diversification. While some studies seek to understand market pricing dynamics (see Riesz et al, 2016; Simshauser, 2018; Marshmann et al, 2019; Ekholm

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[1] In July 2020, a consortium of large companies including Kawasaki announced completion of a 100% hydrogen-fuelled gas turbine. See https://www.nedo.go.jp/english/news/AA5en_100427.html#:~:text=Kawasaki%20has%20been%20developing%20100,verification%20anywhere%20in%20the%20world, Accessed online on 8 August 2021.

[2] One of Japan's leading energy ventures, JERA has announced In the first half of the 2030s, the company wants to achieve a 20% ammonia co-firing rate at all its coal plants, and it is seeking to shift to 100% ammonia by the 2040s. See https://www.powermag.com/jera-planning-to-shift-coal-power-fleet-to-100-ammonia/, Accessed online on 8 August 2021.

[3] We have used \$50/GJ as a proxy for the cost of achieving 'zero emissions' fuel for an OCGT today in the absence of future cost reductions. This represents a price of hydrogen of \$7.15/kg.

and Virasjoki, 2020) much of the literature is focused on establishing an optimal mix of technologies to facilitate 100% renewable energy penetration.

The literature is relatively consistent with most studies noting that it is indeed possible to reach 100% VRE with required complementary technologies including increased transmission and interconnection capacities, demand response, pumped hydro, battery storage and the use of 'zero emission' thermal technologies. Some studies even consider adjacent technology flexibility such as desalination plant integration (see Caldera and Breyer, 2018).

Blanco and Faaij (2018) reviewed 60 studies that considered high penetration renewable systems and the role of complementary technologies. In energy terms, storage was found to be below 1.5% of total annual demand for systems with up to 95% VRE. This increased up to 6% of total annual demand for systems with 100% renewable energy. Shifting from high penetrations to 100% clearly requires a greater volume of storage to address temporal and spatial mismatches of production and demand. Importantly, the review noted that pumped hydro is not sufficient and higher energy density technologies are required. Hydrogen was found to be a prospective technology given its density is 250 times greater than pumped hydro.

While there has been a rapid decline in the cost of battery storage since 2015 (see Dodd and Nelson, 2019; and Graham et al, 2021), Cheng at al (2019) note that 97% of the global capacity of stored power and 99% of storage energy is pumped hydro. As such, many studies continue to be focused on the complementary role of pumped hydro as a balancing technology for high penetration VRE systems. Hydrogen-fuelled gas turbines or fuel cells have not been deployed yet at scale but are increasingly considered as a potential balancing technology for variable renewables (see Nelson, Nolan, and Gilmore, 2021). Some studies have sought to examine the existing economics of hydrogen for complementing solar PV in remote (stand-alone) power systems. Even with current technology costs, CEFC et al (2021) find that a solar PV + hydrogen standalone power system ($387/MWh) is not prohibitively more expensive than a standalone diesel system ($318/MWh).

In the Australian context, there are numerous studies that have sought to understand the dynamics of the electricity system with 100% of the energy provided by VRE. One of the most well-known Australian studies is Wood and Ha (2021) which presented the results of simulation modelling for three VRE adoption 'phases'. For penetrations up to 70%, it was found that costs would be relatively low with only minor changes required for the grid and complementary technologies. Shifting the adoption of VRE up to 90%, however, would require significant augmentation of the grid and adoption of storage but only slightly higher costs. Somewhat controversially in Australia, the study found that adopting 100% VRE would be expensive due to the high costs of overcoming energy droughts in winter.

Blakers et al (2017) developed an hourly energy balance model of the NEM which they utilised to simulate a 100% VRE scenario. They found that geographic diversity of VRE resources reduces storage requirements. Around 90% of annual electricity demand was met with wind and solar with the remaining 10% provided by hydroelectricity (including closed loop pumped hydro) and biomass. The cost of 'balancing' or 'firming' VRE was found to be modest ($25-30/MWh) with the LCOE for the system estimated to be $93/MWh. Lu et al (2017) conducted similar analysis for the South West Interconnected System (SWIS) of Western Australia. The study found that achieving 100% VRE was indeed possible using ~90% wind and solar with integration of off-river pumped hydro providing sufficient balancing. Other Australian studies have focused more on economic issues related to market design and revenue cannibalisation (see Simshauser, 2018 and Marshmann et al, 2019). An optimal sized storage battery was investigated by McConnell et al. (2015). They found the optimal size for firming was about 6 hours.

Globally, there have been a number of studies on regional power markets to determine the feasibility of moving to 100% renewable energy. Zappa et al (2019) considered the pathway and costs involved with shifting the European power system to 100% renewables by 2050. They found that it is indeed possible to source 100% of electricity demand from renewable resources with the same level of adequacy as today. As in the Australian literature, significant augmentation of the transmission system would be required with 240% more capacity found to be necessary. Interestingly, the authors also found that system costs could be 30% higher than a system with nuclear or carbon capture and storage.

Child et al (2018) considered the role of storage technologies for transitioning Europe to a 100% renewable energy system by 2050. The results of their modelling forecast that, even with adoption of the 100% goal and associated storage costs, prices decline by around 27%. The optimal balancing or firming capacity is a mix of batteries, pumped hydro and gas storage (8% synthetic natural gas and 92% biomethane). Creating gas from renewable energy becomes economic when the share of VRE surpasses 50% of the total system. Child et al (2019) make similar findings and note that cost reductions are substantial from increasing interconnection capacity by a factor of approximately four. Steinke at al (2013) note the need for deploying a mix of technologies to provide complementary balancing and firming services. Achieving 100% renewable energy penetration requires firm generation quantities around 40% of overall demand. If the grid is optimised through interconnection and resource diversification, this can be reduced to 20%.

Alexander et al (2015) considered a range of scenarios for the UK in achieving 100% VRE. The study considered a range of firming or balancing options for facilitating 100% VRE: liquid air; hydrogen storage; pumped hydro; and interconnection. While interconnection represented a relatively cost-effective solution, the paper concluded that hydrogen stored in underground caverns would be the most economic solution. Similarly, Child and Breyer (2016) consider the Finnish electricity system and conclude that it is indeed possible to reach 100% renewable energy through the use of energy storage solutions.

In assessing the potential for 100% VRE in East Asia, Cheng at al (2019) note that strong interconnection and demand management can be successfully utilised with off-river pumped hydro storage solutions. Importantly, they find that identified pumped hydro energy storage potential in the region is 100 times greater than the quantity required to support achievement of 100% utilisation of VRE in East Asia. These findings are supported by the work of Lu et al (2021) who note that 100% penetration of VRE is achievable with complementary transmission upgrades reducing costs by ~7% and storage requirements by ~50%.

Esteban et al (2012) considered the storage requirement for a future 100% renewable energy system in Japan. Even though Japan is a relatively small nation geographically with scarce renewable resources and high urban density and energy intensity, an hourly simulation of meteorological conditions found that there was a 100% chance of meeting 40% of electricity demand between 11 am and 6 pm. To allow overall system demand to be met continuously, around 40 TW of storage was projected to be required. The study noted that vehicle to grid storage technology could form a significant component of this storage. Sadiqa et al (2018) similarly find that a 100% renewable energy system is both cost effective and the least cost option for Pakistan's future energy transition.

It is evident that most studies of high penetration renewable energy systems note that it is indeed possible to reach 100% VRE with required complementary technologies including increased transmission and interconnection capacities, demand response, pumped hydro, battery storage and the use of zero emissions thermal technologies. In the subsequent sections of this article, we expand upon these conclusions by considering the role of higher energy density technologies in the Australian context. In particular, we test whether it is indeed possible to reach 100% VRE relatively cost effectively through the use of an optimised mix of pumped hydro, battery storage and 'zero emissions' gas turbines (utilising relatively high-cost biodiesel or hydrogen) to provide system endurance through VRE 'energy droughts'.

3. Methodology and Data

A simplified model of the NEM was created using a custom-developed linear programming tool, the Time Sequential Solver (TSSolver). The model simulates a least-cost portfolio of renewable energy and firming capacity for a system that is created from scratch, with no existing assets included. Future energy costs are therefore likely to be overstated as the value of existing long lived renewable (e.g., hydro) assets will not be captured. However, the future technology mix will highlight which existing assets are most likely to be valuable in the future and what new assets will be required.

The objective function of the linear program is to minimise the total capital and operating costs of building and operating the system to meet the given demand profiles. Through simulating building the capital stock from scratch, no constraints are required to replicate existing coal-plant operating regimes (a feature of many other linear programming models), while other technologies (storage, OCGT) are sufficiently flexible to respond to demand when required.

Given the key role that variable renewables and energy storage are likely to play, the TSSolver was designed to undertake time sequential modelling of energy storage given the variability of wind and solar. This includes optimizing both the expansion plan (capacity of each technology to build) and the dispatch of storage and peaking capacity across the whole study, in a single step. It takes as input the wind, solar, and demand forecasts derived from multiple historical reference years – capturing the historical correlations and variability between each component. This model then simultaneously solves for the least-cost build and dispatch to meet demand across the 43,800 hourly periods of the five reference years.[4]

Demand, wind, and solar hourly reference traces were extracted from AEMO data (AEMO, 2020) for FY21, based on reference years FY15 to FY19. These traces were utilised to expand the amount of VRE available to the system. The NEM was modelled as a single region with no transmission constraints. As such, new build of generation capacity, particularly firming, is likely to be conservative. The base case assumptions were first simulated with all available renewable energy zones, and then a subset of high value traces (ten wind and ten solar traces) were selected as options for the model, based on installed traces. Abnormally high-capacity factor resources (that might require significant transmission costs to develop) were excluded. Unlike many similar expansion plan models, the ratio of stored energy to capacity for energy storage technologies is not pre-determined. Instead, capital costs are linearised into a $/kW and $/kWh component. This allows greater insight into the optimal sizing for batteries and PHES, as well as smoother charge-duration curves. Storage technology parameters were sourced from CSIRO (2020) and were linearised.

The future cost of zero-emissions fuels is difficult to project - as renewable energy costs fall, so too should the cost of green fuels (particularly hydrogen). Conversely, 100% hydrogen gas turbines are not yet commercially available and there will be competing pressures for land use for biofuel production. Therefore, we find it helpful to consider two bookend scenarios: first a base case where cost reductions in production and distribution allow the cost of green fuel to approach that of natural gas (~$12/GJ)[5]; and a high-cost scenario where green fuels are expensive, benchmarked against existing green hydrogen prices (~$50/GJ used to represent an upper limit). The marginal running costs of an OCGT in these cases is set $150/MWh and $600/MWh in these two cases respectively, based on a conservative heat rate of 12GJ/MWh-sent-out.

Capital costs were taken from the 2020 AEMO Integrated System Plan dataset for the year 2040 and are presented in Table 1 below. OCGT peaking units are modelled with a capital cost of $1500/kW. Wind and solar capital costs are $1574/kW and $780/kW respectively. Capital costs were annualised at

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[4] Simulations take 20-40 minutes per scenario per CPU on a 2.4 GHz Intel Core i5. Additional benchmarks were run with nine reference years (78,840 hourly periods) for a subset of scenarios and no qualitative, and minimal quantitative, changes were observed.

[5] This is consistent with modelling from the Australian Energy Market Operator in their 2022 Integrated System Plan project, which projects that hydrogen turbines could be powered at $10-14/GJ fuel under a “Hydrogen superpower” scenario after 2030.

a conservative 6% real pre-tax WACC. Peak electricity demand is assumed to be ~31.7 GW with annual consumption of 171 TWh.

Table 1: Key capital cost assumptions

	Capex		Connection	FOM		VOM	Life	Roundtrip
	$/kW	$/kWh	$/kW	($/kW)	$/kWh	($/MWh)	(y)	Efficiency
Wind	1474		100	40		0.00001	25	
Solar	680		100	15		0	25	
Peaker	1373		100	4.5		0	25	
Battery	207	143	0	0	5	0	15	0.81
PHES	1828	63	0	17	0	0	30	0.8

Source: AEMO 2020 ISP

A value of customer reliability (VCR) or market price cap of $50,000/MWh was used in the model, which is at the upper range of estimations in Australia (see AER, 2020). A conservative value was chosen to offset other assumptions, such as lack of transmission constraints. Finally, all storage entry is fixed at 100% to avoid scenarios where a low-output VRE period early in the study would disadvantage storage options.

Several scenarios were modelled to determine the optimal mix of storage in a market with 100% VRE penetration:

- Base case (1) – all firming technologies are included as options for the model to optimise the build of storage

- No storage (2) – only thermal technologies (OCGT units) are included (at current fuel prices of ~$12/GJ)

- No peakers (3) – only battery storage and pumped hydro are included

- Only batteries (4) – pumped hydro and thermal technologies are excluded as options for the model to optimise the build of firming capacity

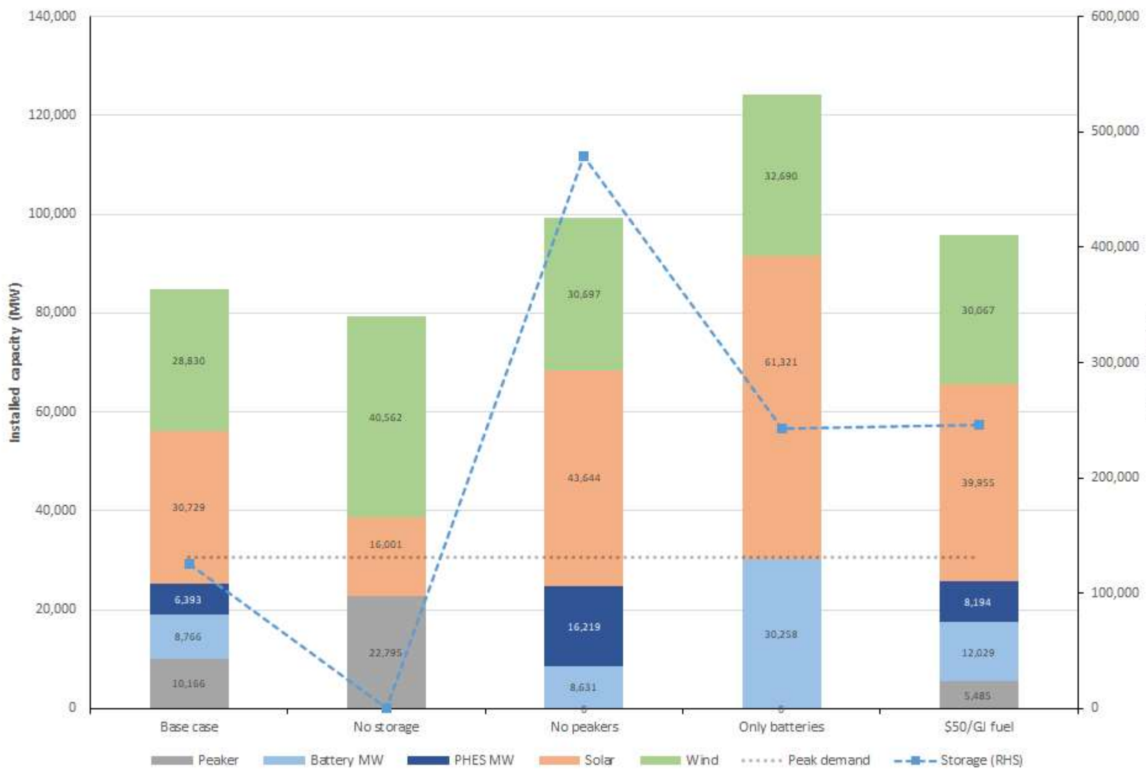
- $50/GJ fuel (5) – to test the sensitivity of OCGT units, all firming technologies are included as options for the model to optimise the build of storage, but thermal technologies are included with fuel prices of $50/GJ, and storage is modelled with a 20-year life.

By assessing these five different scenarios, we are able to test the optimal technology mix for meeting a very high penetration of renewables within the Australian NEM. To be clear, the 100% VRE is not the objective function of the modelling. By allowing *energy* to be produced by wind and solar (and not mid-merit gas or coal), the model either achieves 100% energy from VRE (scenario 3 and 4) or levels close to 100% (scenarios 1, 4 and 5). Our main consideration is whether renewable thermal technologies are likely to be economic to allow for security of energy supply given the potential for 'energy droughts'.

4. Results

The new capacity build and storage output for each of the five main scenarios is presented in Figure 1. The Base Case least-cost build comprises a mix of wind and solar, firmed by 6 GW of 13-hour PHES, 9 GW of 4.6-hour batteries, and 10 GW of gas peakers (recall these have a marginal running cost of $150/MWh). This portfolio is sufficient to supply demand at all times, with no load shedding, across the five yearly demand traces (FY15 through FY19) modelled.

Figure 1: Capacity installed (MW) and storage output (MWh)



The other four cases provide some specific insights into how the market will operate depending upon different technological assumptions. If no storage is permitted, there is a distinct skew towards wind over solar with an additional ~12 GW of wind being installed and ~14 GW less solar. This is driven by the greater temporal diversity of wind production. Around 23 GW of peaking plant is installed (producing energy at a marginal running cost of ~$150/MWh). If peakers are not permitted, the optimal mix shifts significantly back towards solar with around ~44 GW and ~31 GW of solar and wind installed (reflecting solar being the cheaper energy to produce and store). The optimal mix of storage is ~16 GW of pumped hydro and ~9 GW of batteries.

Scenarios 4 (only batteries) and 5 ($50/GJ fuel) provide insights into the optimal mix of technologies across all four scenarios. In the case of Scenario 4 (only batteries), there is a significantly higher build of renewables with around 94 GW of total installed capacity with two-thirds of this being solar. Scenario 5 ($50/GJ fuel) shows that significantly less renewables are required (~70 GW or two thirds of the case when only batteries are permitted). Importantly, the use of 'renewable' peakers in Scenario 5 results in a very similar outcome as Scenarios 1 through 3. There is a mix of pumped hydro (~8 GW), batteries (~12 GW) and peakers (5.5 GW).

The conclusion from these scenarios is that even with very high fuel costs of $50/GJ (representing 'green' fuel costs), the least cost new build solution is still to deploy a limited number of these assets to reduce the total capex on renewables and other storage technologies. Importantly, the peakers operate with capacity factors of only 2% (40 Equivalent Operating Hours (EOH) per year) but are very high value when needed at very infrequent intervals (to handle energy drought conditions). In some instances, the peaking units run continuously for up to 65 hours (Figure).

Figure 2: Example of time series showing deployment of firming capacity

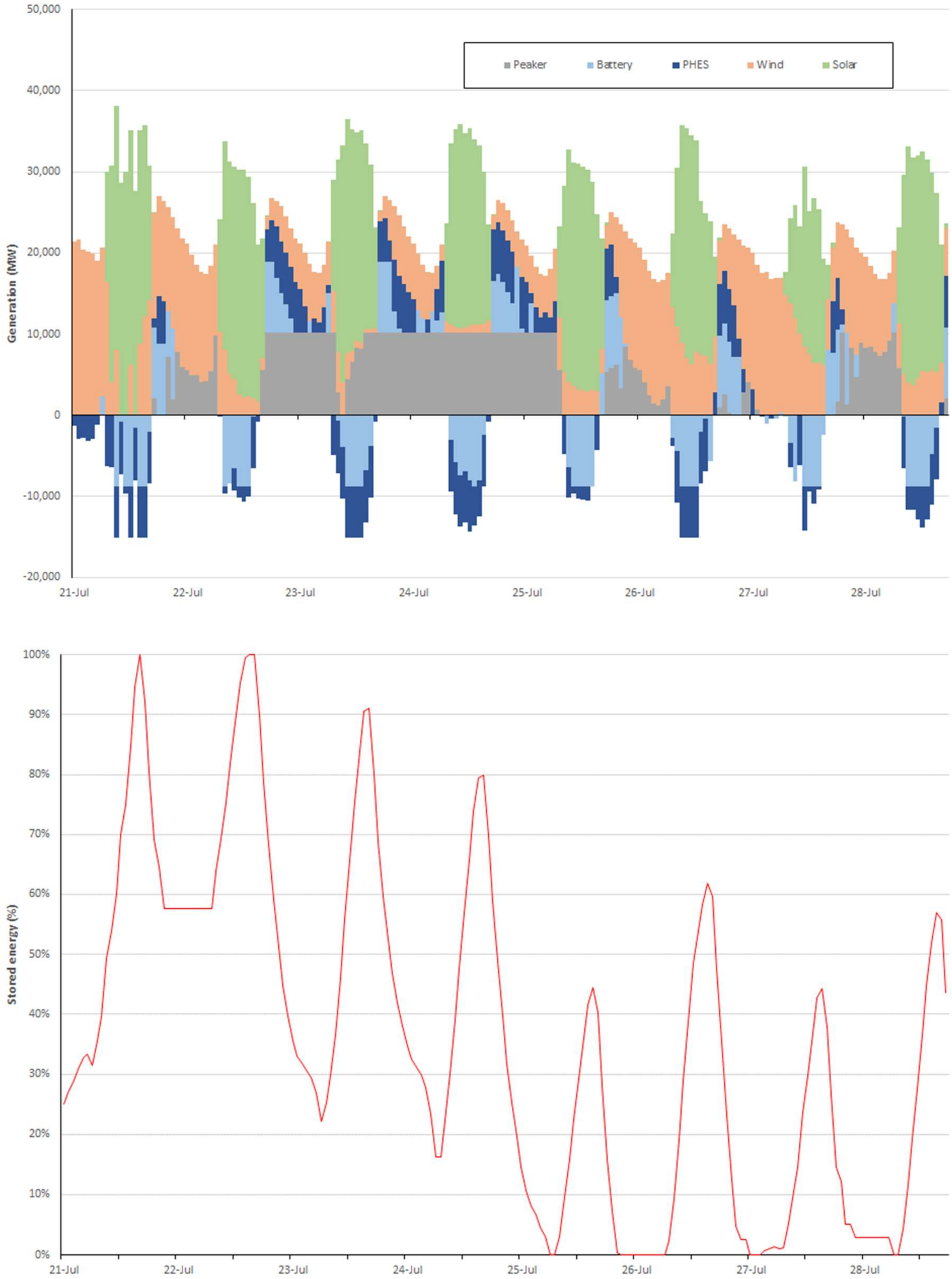
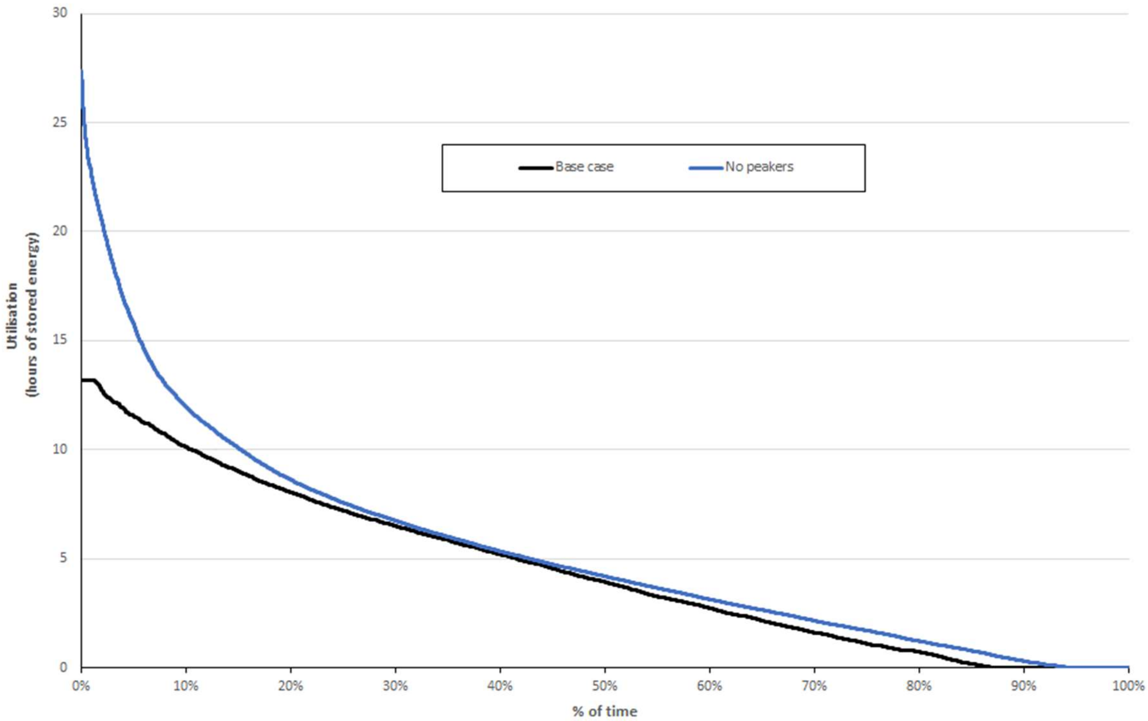


Figure 2 shows a scenario in which classic 'dunkelflaute' conditions persist[6]. Over the course of this particular week of demand and solar/wind trace data, it is clear that peaking assets become necessary to manage the depletion of storage assets driven by the absence of wind and solar resources. The peaking assets in both the Base Case and $50/GJ fuel Case have relatively low capacity factors but their operation is skewed towards operating in these 'energy drought' conditions. This is particularly the case during 'dunkelflaute' conditions – a finding that aligns with that of Wood et al (2021). The novel finding in this study, however, is that even with very high fuel costs the least cost capacity build includes new OCGTs.

If peakers are not permitted to be deployed (Scenario 3), demand is met by deploying additional VRE and storage. Four times as much stored energy is required to run through these periods of 'energy drought' when compared to the Base Case (Scenario 1) and twice the amount when compared to the $50/GJ Case (Scenario 5). Importantly, the final three hours of storage are used only once over the five years. This is shown in the storage charge duration curve presented in Figure 2.

Figure 2: Storage charge duration curve



The storage duration curves for Scenario 1 (Base Case) and Scenario 3 (No Peakers) shown in Figure 3 show the material holding cost[7] of storage when peakers are not permitted. The significant additional storage costs are compounded by the additional wind and solar capacity required to generate the storage energy. Accordingly, the average cost of meeting electricity demand is around 15% higher in the No Peakers Scenario than the Base Case (see Figure 4).

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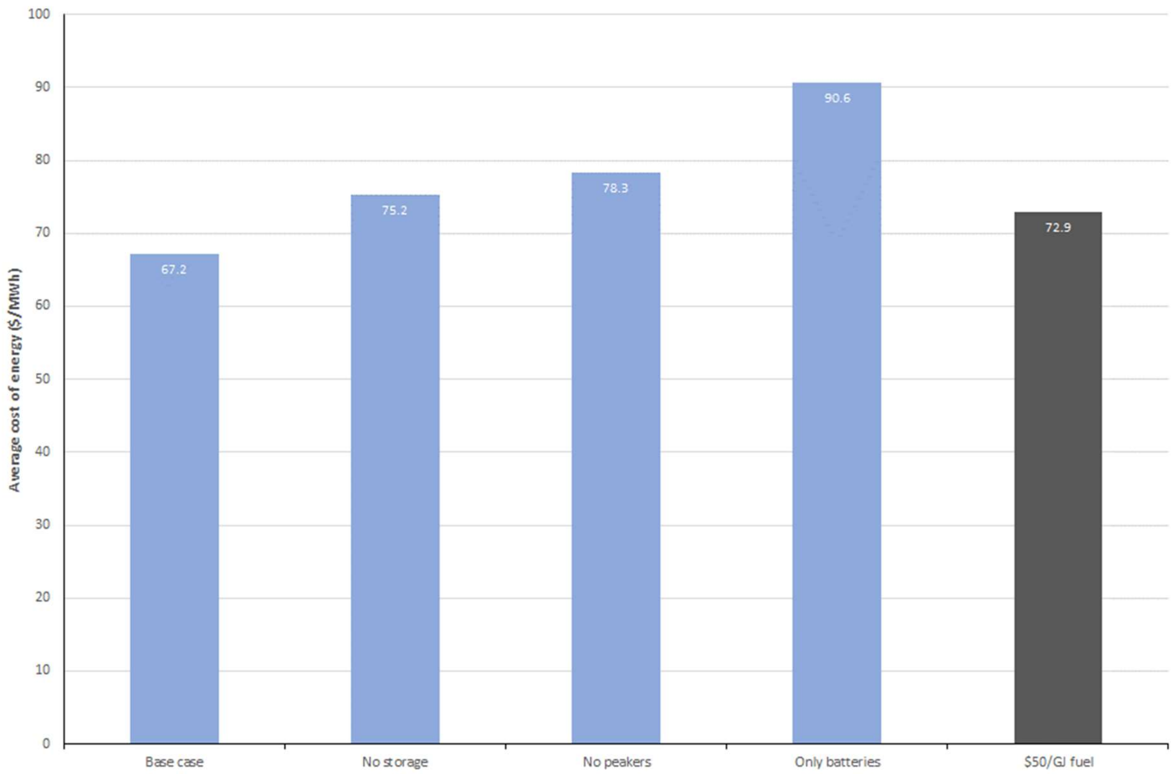
[6] Dunkelflaute is a German word referring to 'dark doldrums or dark lull' – in the energy context, the period in winter where there are poor wind and solar resources for a prolonged period. It is a reference to a particular type of 'energy drought'.

[7] Holding cost refers to the cost of building capacity that is rarely used.

Figure 4: Average cost of energy by scenario



The average cost of electricity (total costs divided by total consumption) for each of the five scenarios is presented in Figure 4. As noted above, the holding cost of storage is material and it significantly influences the results. The lowest cost scenario is unsurprisingly the Base Case where all possible lowest cost technologies are included (at $67/MWh). Interestingly, the next most economic case is the $50/GJ fuel case which is $5.70 higher (at $72.9/MWh) and relatively economic compared to current wholesale pricing in the NEM (which averaged ~$75/MWh over 2018-2020).[8] This is an important finding for policy makers which we will explore in further detail in the subsequent section but shows that very high-cost peaking generation may still be economic due to its duration advantage (despite relatively low capacity factors). Put simply, there is likely to be a role for 'zero emission' or 'renewable' thermal plant to provide energy security during times of prolonged VRE energy droughts.

The costs associated with the other three scenarios also provide important insights for policy makers to consider. By limiting the availability of firming technologies, costs significantly increase. Scenario 2 (which removes storage), Scenario 3 (which removes peakers) and Scenario 4 (which removes peakers and pumped hydro) increases costs above Scenario 5 ($50/GJ fuel) by 3%, 7% and 24% respectively. The implications of this analysis are clear: policy makers should be focused on allowing a mix of storage and zero emission peaking technologies. The rich diversity of capital and operating costs and operating capabilities will make all of them economic for servicing different parts of the load duration curve in a market with increasingly variable supply (due to VRE adoption) and demand (due to digitalisation of energy consumption).

To be clear, storage is key for achieving a least-cost solution. Storage can shift low-cost solar energy from the middle of the day to the evening peak. However, as shown in Figure above, in a small

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[8] While this simplifications in this modelling will likely underestimate total costs and caution should be exercised in comparing average costs of this modelling with current pricing, it suggests that a 100% renewable energy system need not impose higher costs on consumers even when carbon externalities are included. In fact, market prices could be even lower given the sunk cost of existing high value hydro and pumped hydro assets.

number of circumstances it can also be efficient for storage to charge at times of high peaking generation (at either $150/MWh or $600/MWh) to store energy when VRE is projected to be low. This is not just theoretical; charging storage from higher priced energy is already occurring on a limited scale in the NEM. For example, on 12 March 2021, a South Australian battery charged during prices of ~$10,000 in order to generate at a later higher price of $15,100/MWh. Without storage, average costs are ~10% higher than the Base Case, even though less total capacity is developed. Both capacity *and* energy can be limiting factors for a future 100% VRE system.

4.1 At what comparative cost structure will storage be preferred over peakers?

Our modelling has been largely focused on understanding whether significant increases in marginal running costs of peaking generation could be accommodated to reflect 'zero emissions' fuel and still be economically deployed to meet electricity demand. It is also worth considering the comparative cost conditions that would shift the least-cost capacity build away from OCGT peaking generation and towards pumped hydro and battery storage. Given the pace of technology change, it is credible that battery storage costs could fall faster than projected. We therefore ran additional simulations of the model with a further 25% reduction in $/MW battery costs and up to 75% reduction in $/MWh battery costs (on top of the significant cost reductions already assumed as part of our AEMO ISP dataset). Cost reductions for pumped hydro are taken to be less likely but it is conceivable that good sites could achieve a lower cost than projected. Accordingly, we therefore simulated scenarios with a 25% reduction in PHES $/MW costs and 50% in $/MWh costs.

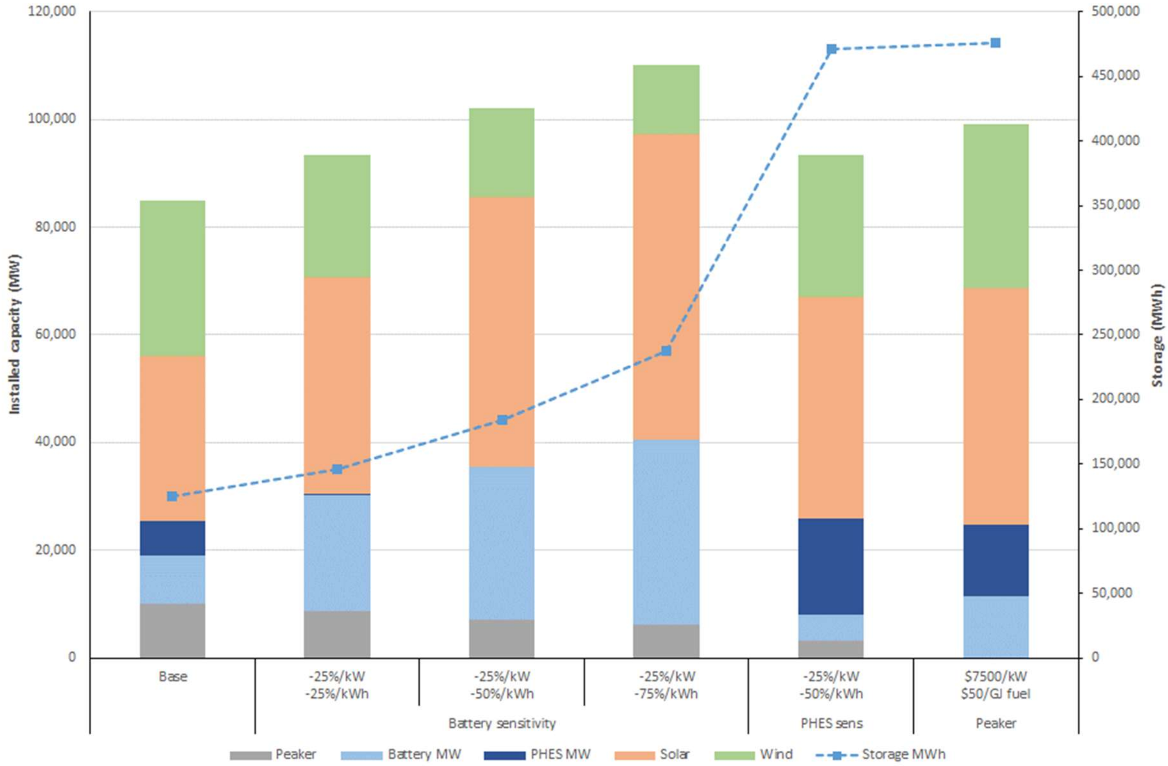
Conversely, there is a risk that the capital cost of 'zero emissions' or 'renewable' fuel peaking units will be materially higher than anticipated. We have been unable to find any Original Equipment Manufacturer (OEM) that currently provides pricing for 100% 'hydrogen ready' gas turbines in Australia.[9] Our desktop research shows that only high percentage turbines are being deployed cost effectively. For example, Australian utility EnergyAustralia recently announced financial close for a new gas turbine with the goal of progressively increasing the hydrogen/natural gas blend to '60% hydrogen'. Importantly, this is fuel by volume and not energy. The different energy densities of hydrogen and natural gas results in the turbine being powered by 35% hydrogen by energy, and hence a much smaller reduction in emissions. [10] The 'extreme upper bound' of potential capital cost outcomes is therefore likely to be the capital cost of hydrogen fuel cell technology. Accordingly, we have tested an upper bound sensitivity with peaking unit capital costs increased to five times the Base Case ($7500/kW) and with $600/MWh running costs.

The results from our sensitivity analysis are presented in Figure 5. As storage costs fall, capacity builds shift towards storage (as expected) which is backed by significant additional installed wind and solar capacity. These results imply that with lower capital and operating costs for BESS, it becomes more economical to build additional capacity for energy and shift it intra-day with storage. Importantly, batteries are almost exclusively deployed to meet storage requirements at the expense of pumped hydro. 'Renewable' peaking units remain part of the energy mix across the lower storage cost scenarios (although in smaller capacities). Peaking units are only completely excluded in the most extreme scenario, where the prohibitively high capital costs ($7500/kW) make them completely uneconomic relative to batteries and pumped hydro.

[9] It should be noted that OEMs do indeed market 'hydrogen ready' gas turbines. Our informal conversations with limited number of OEM participants in the Australian context indicate that the capital costs of '100% hydrogen capable' turbines are unlikely to be *materially* higher than existing machines, but the market is limited by demand (given limited availability of renewable hydrogen). See for example, GE's website that markets aeroderivative machines as ~80% hydrogen blend ready and B/E and F-class machines as ~100% hydrogen blend ready (see https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines, Accessed online on 13 January 2022).

[10] See https://reneweconomy.com.au/hydrogen-will-be-cover-for-a-new-life-for-fossil-fuels/, Accessed online on 13 January 2022.

Figure 5: Capacity (MW) and storage (MWh) in cost sensitivities



4.2 *Impact of hypothetically severe wind and solar droughts*

While the nine years of modelled reference year data captures some of the variability of the underlying resource, it may not be sufficient to capture: a) poorer performance from projects developed with imperfect foresight; or b) very extreme weather droughts, driven by extended periods of poor wind and solar resources not captured in historical data. 'Renewable' peaking units provide insurance against very extreme weather events that may not be included in the simulated inputs. The risks of such (renewable energy) droughts are not well defined in Australia. Security of supply has historically been provided through 'gains from exchange' from incumbent depreciated coal assets but these assets will not be capable of providing this in the future.

Two further sensitivities are therefore modelled for the purposes of this study: a 'Mild Drought' where each VRE trace is limited to 30% of its output in any given hour for seven days; and a 'Severe Drought', where all VRE assets are limited to 10% of their output for seven days. Put simply, the combined VRE output in any hour is, *at most,* 10% of the installed nameplate capacity, but can be less if any individual trace was already operating less than 10%. We do not purport that there is any science behind these arbitrary VRE output limitations. Instead, we include them as insights for policy makers about how markets could be designed to respond to the uncertainty of VRE energy droughts.

Figure 6 shows the changes in installed 'renewable' peaker capacity and energy storage for these two new simulations. Unsurprisingly, extended energy-short periods lead to greater peaking capacity in all of the scenarios where peaking generation is permitted to be installed (even the very high 'renewable' capital and operating costs scenario).

Figure 6: Peaker capacity and stored energy in drought scenarios

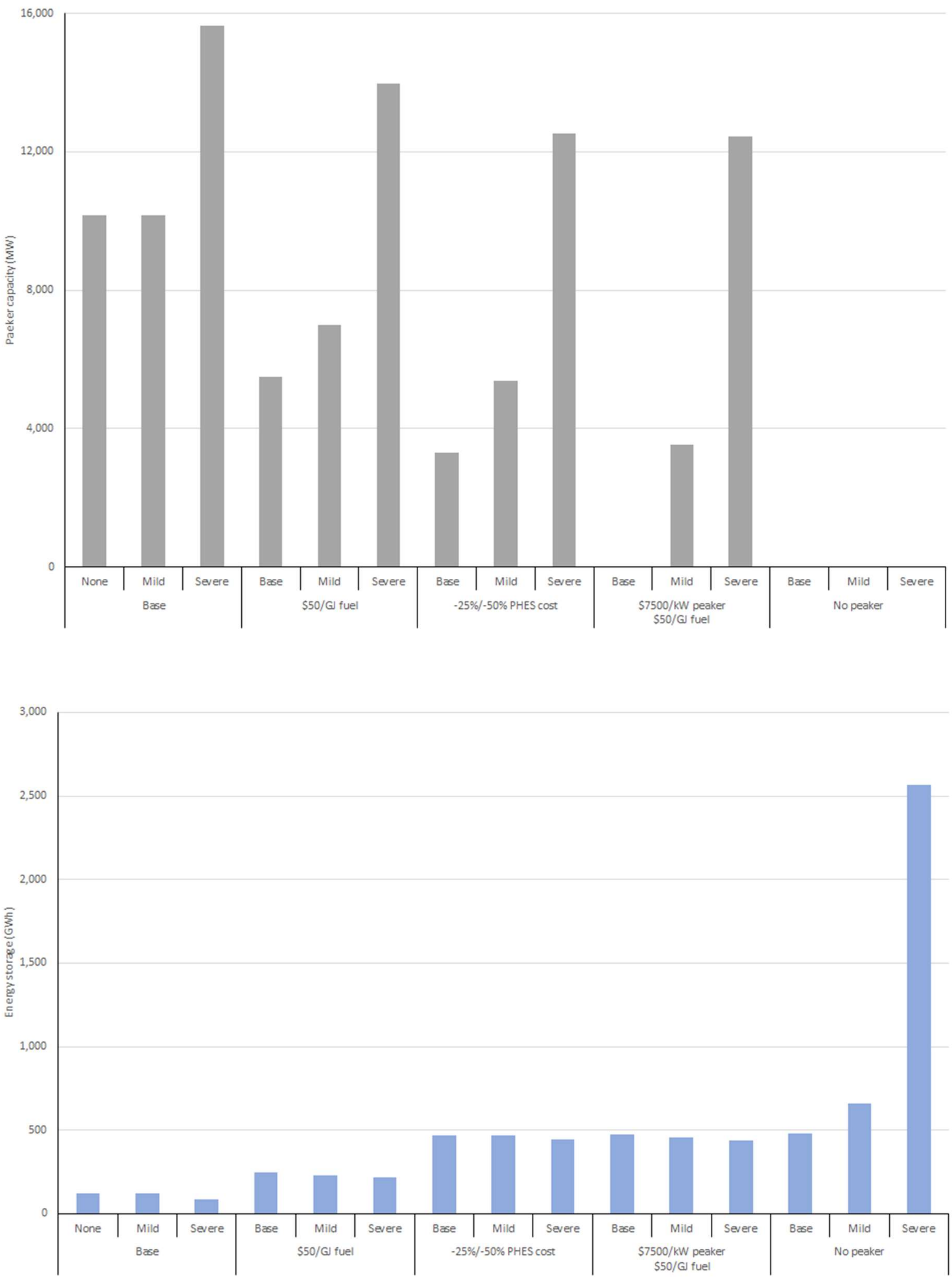


Figure 6 shows that the ‘mild drought’ conditions do not materially change the optimal installed ‘renewable’ peaking capacity and stored energy (in GWh). However, ‘severe drought’ conditions result in installed capacity tripling from around 4-5 GW to around 12-15 GW across the $50/GJ and changed capital costs scenarios. Effectively, such ‘severe droughts’ result in energy storage being an uneconomic option relative to deploying much higher operating ($50/GJ) and capital ($7,500/kW) cost ‘renewable’ peaking technology. If capital costs are not similar to those of current peaking technologies, this could have non-trivial implications for average system costs (presented in Figure 7).

Figure 7: Average cost of ‘mild’ and ‘severe’ drought scenarios

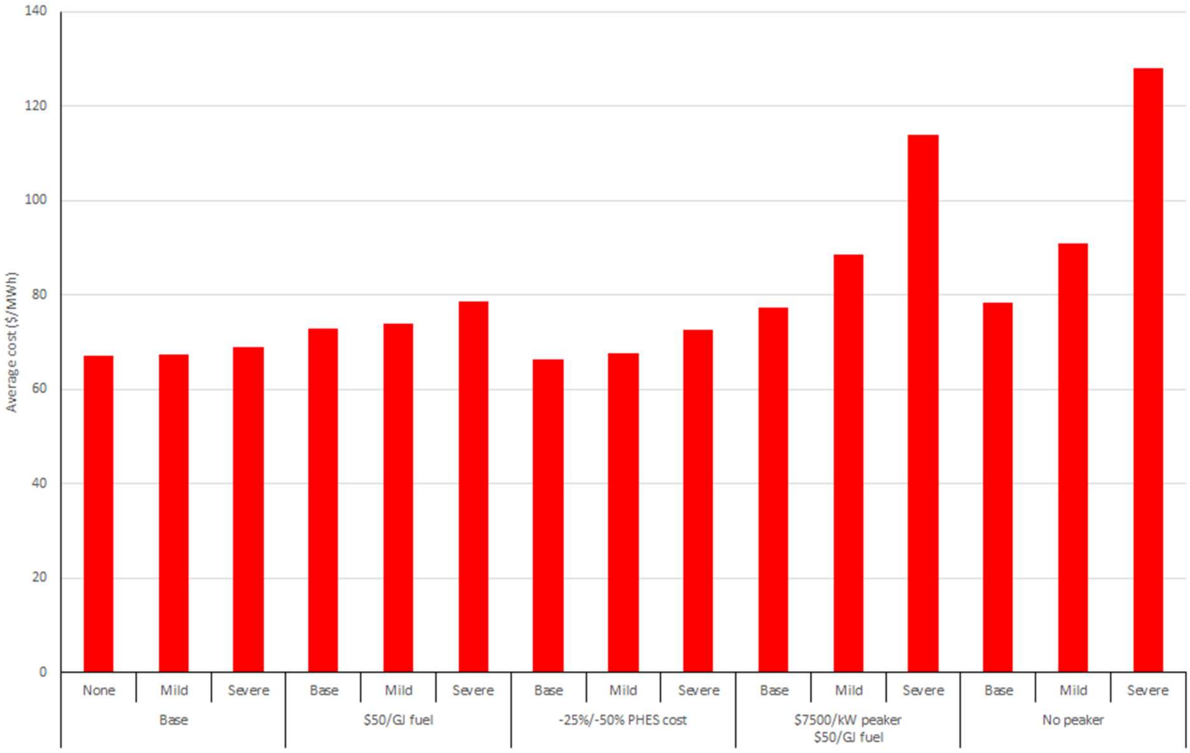


Figure 7 shows the average cost of ‘mild’ and ‘severe’ energy drought simulations across various scenarios. Interestingly, the average cost is similar for drought conditions in the Base Case ($150/MWh marginal running cost peaking generation), the $50/GJ peaking generation scenario and the lower pumped hydro and battery capital cost scenario. However, simulated energy drought conditions result in an increase of cost from around $75/MWh to $115/MWh when peaking capital costs are higher. This effectively represents the materially higher capital costs of ~12,000 MW of ‘renewable’ peaking generation spread across all MWh consumed.

The costs are even higher, however, in the scenario where no peaking generation is permitted to be built. The average system cost increases to almost $130/MWh and requires as much as ten times the stored energy. Much like the debate around poor capacity utilisation in electricity networks, policy makers will need to consider whether significantly increasing storage capacity as an ‘insurance’ against energy droughts is necessary if ‘renewable’ peaking technologies could be used instead (with the benefit of being able to sell temporally surplus hydrogen via ‘green hydrogen’ export markets). Importantly, although higher levels of peaking capacity are developed to manage ‘severe’ droughts, the volume of energy storage does not reduce significantly. This suggests that peaking capacity is largely complementary to, rather than competing with, energy storage as an efficient firming strategy. Furthermore, pricing and reliability outcomes are likely to be more robust to a range of demand and weather scenarios when peaking capacity is available – additional energy can be readily injected (which can then be smoothed and arbitraged by the storage units), whereas storage alone provides few “real time” levers.

4.3 *Distribution of pricing*

Hourly prices in TSSolver reflect both short-run and long-run incremental costs. In other words, the marginal cost of serving an additional megawatt of demand in a particular hour may be the marginal running cost of a 'sunk' peaking plant (already deployed to meet demand for a separate time period), or it may include the additional capital required to build new capacity. Prices are capped at the VCR (as load shedding is always a last-resort option in the model). While these prices do not necessarily represent the spot prices that would occur in a real-time spot market with oligopolistic bidding, they represent a reasonable proxy of the volatility required in a pure energy-only market.

Most markets, including the NEM, cap spot prices at levels below the real VCR. In the NEM, this is achieved in two ways: a Market Price Cap (MPC) of $15,100/MWh (as of 2021-21) that applies to any individual dispatch interval, and a Cumulative Price Threshold (CPT) that limits consumers' exposure to extended high prices. The average wholesale price over any rolling 168-hour (one week) period cannot exceed $1,348/MWh or prices in any subsequent period are administratively capped at $300/MWh.

These practical compromises lead to the risk of 'missing money' which has been a well discussed risk in the context of energy only markets (see Billimoria and Poudineh, 2019, for a good summary of missing money). This 'missing money' is mitigated by transient market power, allowing prices above the marginal unit's running cost and market participants typically manage these financial risks through either vertical integration or through the sale of cap contracts that act as the de facto capacity market product. These contracts are options that pay out when wholesale prices exceed a strike price (typically $300/MWh, representative of the marginal running cost of a liquid fuel peaking unit in the current market). These options trade at a premium to actual spot prices. Simshauser and Gilmore (2021) note that cap contracts have traded at an average price equal to the annualised cost of a new entrant (gas) plant.

While much attention has been given to the role of MPC, the CPT is also important. Our results indicated that either the MPC or the CPT would lead to approximately $1bn in 'missing money' per annum in the Base case, equivalent to ~10% of annualised capex and fuel costs. This is concentrated on firming assets: VRE projects see only <2% 'missing money', while storage and peaking capacity experience 17-27% 'missing money' due to the MPC and/or CPT.

In the Base Case, the MPC is the more significant constraint, reflecting shorter duration extreme events. However, in the 'severe' drought simulation, the CPT contributes the majority of the missing money ($800m vs $300m for the MPC). This is because the necessary firming capacity for the long-duration energy drought only operates for a small number of hours. Acknowledging that strategic bidding would provide some opportunity to recover missing money in other periods and the NEM's liquid contract market typically provides a premium beyond spot-market revenues, our modelling indicates that a doubling of the existing CPT and MPC would be required to overcome this problem. This is not necessarily a significant issue and could be progressively implemented over the coming decade.

5. **Policy Implications**

Our results show that in a 100% VRE supplied energy system, there is likely to be a need for some type of thermal plant that utilises a zero emissions fuel. While pumped hydro and battery storage will ensure system reliability for shorter duration absences of wind and solar energy, prolonged 'energy droughts' (particularly in winter) require a technology that can utilise deeper reserves of energy. In our view, three significant policy implications flow from our analysis: scaling investment in zero emissions thermal plant technology; introducing a mechanism to increase the production of 'clean fuels' within the natural gas network; and market design and the need to focus on incremental change to the existing energy-only market rather than introduce significant and unnecessary change.

Scaling Investment in Zero Emissions (Renewably Powered) Thermal Plant Technology

While we see a key role for renewable fuel-based technologies in the future grid, projected installed capacity and capacity factors remain not dissimilar to current NEM experience. Peakers operate with a capacity factor of 2-8%, which is very similar to historical OCGT capacity factors in the NEM. Similarly, the 10 GW of peaking capacity in the Base case aligns with the approximately 10 GW of peaking capacity (OCGT+CCGT) across the NEM. A key question for governments and investors is how many of the existing gas turbines could be converted to zero emissions fuel, and how much new capacity is required.

A policy response to this issue would not just produce benefits for the domestic Australian electricity industry. Australia is among the world's largest energy exporters. Coal (14.8%) and gas (10.6%) represent approximately one in four Australian exports (by $). Australia is currently the largest exporter of coal (thermal and coking). Approximately 30% of all coal exports originate from Australia and Australia is the largest exporter of LNG. Australia's largest energy trading importers have all committed to net zero and are shifting consumption away from Australia's fossil fuel exports.

Australia is one of the countries that could benefit most from the development of 'green hydrogen' technology as a large green hydrogen export industry could replace the significant energy exports currently derived from coal and gas. Accordingly, producing low-cost hydrogen and ammonia has become an official goal of the Australian Government. However, ignoring how low-cost hydrogen could be integrated within electricity networks via scaled investment in zero emissions thermal plant technology is a current policy oversight. To be clear, we are not advocating for costly investment in CCS technology but instead indicating that Australian governments would benefit from developing a policy to encourage deployment of very high blends of hydrogen within existing and new gas turbines in Australia's NEM.

There is precedent for this type of technology specific focus with the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC) having funded early-stage battery developments. Governments could transparently provide funding through tender processes to new gas-turbine technologies that incorporate very-high and 100% hydrogen capabilities. It would be important that governments use input-side subsidies, such as concessional finance, rather than Contracts-for-Difference (Cfds) and other market subsidies (see Nelson et al, 2022, for further discussion of the limits of Cfds).[11][12]

A mechanism for increasing the proportion of 'clean fuel' within the gas network

In addition to developing policy responses to encourage deployment of new 'hydrogen ready' gas turbines, governments could consider ways of transitioning Australia's gas network to hydrogen. This would both increase the proportion of hydrogen within existing gas turbines, and it would also assist gas networks plan for a decarbonised future and avoid stranded asset risk. While we do not contend to have a scientific understanding of the engineering requirements for retrofitting pipelines to be capable

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[11] As an example, the NSW Government's 2 GW firming underwriting policy could be refocused on development of the green hydrogen economy.

[12] Relatively 'risk averse' governments could also support deep storage which might be available at relatively low marginal cost (for example, additional hours of storage on a PHES can often be added at low marginal cost). Indeed, the Australian government recently invested in a 2000 MW, 175 hour PHES system ("Snowy 2.0"). However, unless government interventions are kept out of the market, they risk simply displacing private investment (which is more likely to be optimal and exposes investors, rather than taxpayers and consumers, to stranded asset risk.

of carrying natural gas, we do note support for this concept from existing Australian gas market participants[13] and the existence of voluntary trials[14].

Such a mechanism could be modelled on the existing Renewable Energy Target (RET). Gas retailers could be required to progressively increase the proportion of 'renewable' gas procured and sold within the existing gas network. This could be achieved by enabling producers of green hydrogen and biogas to produce Renewable Gas Certificates (RGCs) which would need to be purchased and surrendered to the Clean Energy Regulator to meet their market share of a prescribed target (e.g. 10%). Targets could be progressively increased which would provide both the gas supply and transportation (pipeline) sector with some confidence about the cost-effectiveness of transitioning their infrastructure and business models.

Market Design

Perhaps the most contested part of Australia's current energy policy debate (and the implications of this paper) relates to market design. The Energy Security Board is currently designing a new capacity market to be considered for approval by Australian governments in 2022. Importantly, the Australian state governments have indicated that, while work on the design of a capacity market can be progressed by the Energy Security Board, they are not yet convinced that one needs to be implemented. As such, the implications of this paper need to be considered carefully in light of the potential for changes to Australia's energy-only market design.

Our modelling shows that it is likely that many firming resources will only be required rarely, to manage low probability, high impact events. In our view, future market settings will need to be adjusted to address these risks – providing signals for both brief but large capacity shortages (sufficiently high MPC) and extended energy shortages (sufficiently high CPT). Following a major state-wide system black event, some governments seem unwilling (or unable) to accept anything less than 100% reliability, even if this is costly for consumers.

In relation to capacity markets, it is clear that the problem being debated within Australia relates primarily to the amount of 'insurance' governments believe consumers should pay for to deliver very high levels of reliability. Delivering the necessary energy resources requires i) a clear assessment of the potential supply and demand side risks and ii) agreement over which risks are to be mitigated and which are to be accepted, and iii) agreement over how much 'buffer' to be paid for to insure against 'unknown unknowns'. While capacity markets (like energy only markets) have been an effective tool at managing brief capacity shortages, their ability to value and efficiently deliver resources to manage extended energy shortages is much less clear.

Particularly infrequent events (such as an 'energy drought') may be beyond what a prudent retailer is likely to hedge exposure to (through derivative markets). This is not unprecedented as retailers do not hedge against very low probability but very high consequence weather events (e.g. one in twenty year summer peak demand). These high impact but very low probability events are best managed through explicit interventions and policies that reserve capacity or energy to manage extreme events. For example, an operating reserves market ensures that some capacity (or appropriately compensated demand response) is always available to manage unexpected events and can be used to achieve reliability beyond the market price settings. To deliver firming beyond what market participants would otherwise deliver, these reserves must be held out of the market – useable as a 'reliability hedge' but not a 'price hedge'.

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[13] For example, see https://jemena.com.au/about/newsroom/media-release/2021/jemena-calls-for-renewable-gas-target, Accessed online on 13 January 2022.

[14] See https://reneweconomy.com.au/wastewater-biogas-to-lead-nsw-renewable-gas-certification-scheme/, Accessed online on 13 January 2022.

Given our modelling shows that firming resources will be required only infrequently, we contend that any capacity market intervention in Australia should be specifically focused on *new* capacity in resources that meet the requirements of future market evolution. Specifically, providing policy support to existing coal-fired generators simply fails the public interest test on two fronts. Firstly, the future market requires generation that can turn on and off quickly (adjusting to consumers' increasing appetite for installing their own solar PV). Hydro, gas and batteries fit this description, not coal-fired power stations. While coal-fired power stations have the right maximum capacity, they are too inflexible to be able to deliver increases in supply when it counts (e.g., the end of the day when all solar PV stops producing at the same time).

Secondly, Governments also need to consider the very significant financial assistance already paid to coal-fired generators when the Clean Energy Future package was introduced in 2012 and repealed only two years later. None of the ~$5 billion in assistance provided to coal-fired generators was paid back to taxpayers. Asking consumers to pay again for these power stations to 'stay in the market' via a capacity market payment doesn't seem fair or equitable. Any mechanism that prolongs the life of coal-fired power stations is likely to result in poorer reliability outcomes and will only serve to delay investment in the critical technologies that the evolving market requires. As such, we strongly recommend that policy makers focus capacity market intervention exclusively on *new* investment in flexible, zero emissions technologies.

It is very clear that if there is a problem with the *current* market settings, it relates to the lack of a forward view of the MPC and CPT.[15] A clear solution to this problem is for the AEMO Integrated System Plan to inform the Australian Energy Market Commission (AEMC) Reliability Panel's role in relation to the MPC and CPT. With the publication of each ISP, the Reliability Panel could be tasked with providing a fixed MPC and CPT for the following year but also guidance on the likely MPC and CPT in each year for the following decade. This guidance could include an upper and lower bound rather than a specific recommended $ value for each year.

By introducing both a carefully design capacity/operating reserve mechanism and a forward view of the required MPC and CPT, market participants would be well placed to consider the optimal suite of investments given long-lived asset lives. Our modelling shows that this is likely to require all three technologies – peaking generation, battery storage and pumped hydro. In the short to medium term, most investment is likely to be in battery storage which our analysis shows has a key role to play with around 15-30 GW of new capacity required (based upon existing demand levels). We have included further analysis of the short-term economics of battery storage in Appendix 1.

6. Conclusion

This article has presented the results of modelling Australia's NEM in a future where all meaningful energy requirements are sourced from variable wind and solar production. Specifically, our modelling considered the economics of different firming technologies and their potential for cost effective operation during 'energy drought' conditions to ensure security of energy supply when wind and solar resources are scarce for prolonged periods of time. Our hypothesis was that even at current very high fuel costs of ~$50/GJ, 'green gas' or 'green hydrogen' may be economic for providing very infrequently utilised capacity to address extreme low probability but high consequence energy drought events.

Our findings are relatively clear that some form of green fuel-based peaking generation is likely to be required, even if costs are relatively high (both capital and operating). This builds on earlier work completed in Australia by Wood et al (2021) who considered the role of peaking thermal technology

[15] It has also been argued that market liquidity has become an issue within Australian electricity markets due to market concentration. Governments already have tools available to mitigate this such as the Market Liquidity Obligation which can be triggered to require large market participants to provide buy/sell spreads on derivative products daily. Despite having access to this policy tool, the Energy Security Board seems disinterested in applying it and is instead focused on a capacity market which would include subsidies to fully depreciated coal-fired power stations.

at current cost structures. By showing that the technology is likely to be required even at a comparatively high cost structure, our analysis has important policy implications for governments across three main dimensions.

Firstly, governments need to scale investment in zero emissions (renewably powered) technology by working with the domestic industry and OEMs to increase the deployment of very high penetration green hydrogen or biogas turbines. Secondly, governments could consider the introduction of a Green Gas Target modelled on Australia's existing Renewable Energy Target to drive investment in hydrogen production. And finally, policy makers need to pivot the current capacity market debate towards integrating *new* capacity incentives through a blended new capacity/operating reserve market and a forward looking signalling of market price cap settings.

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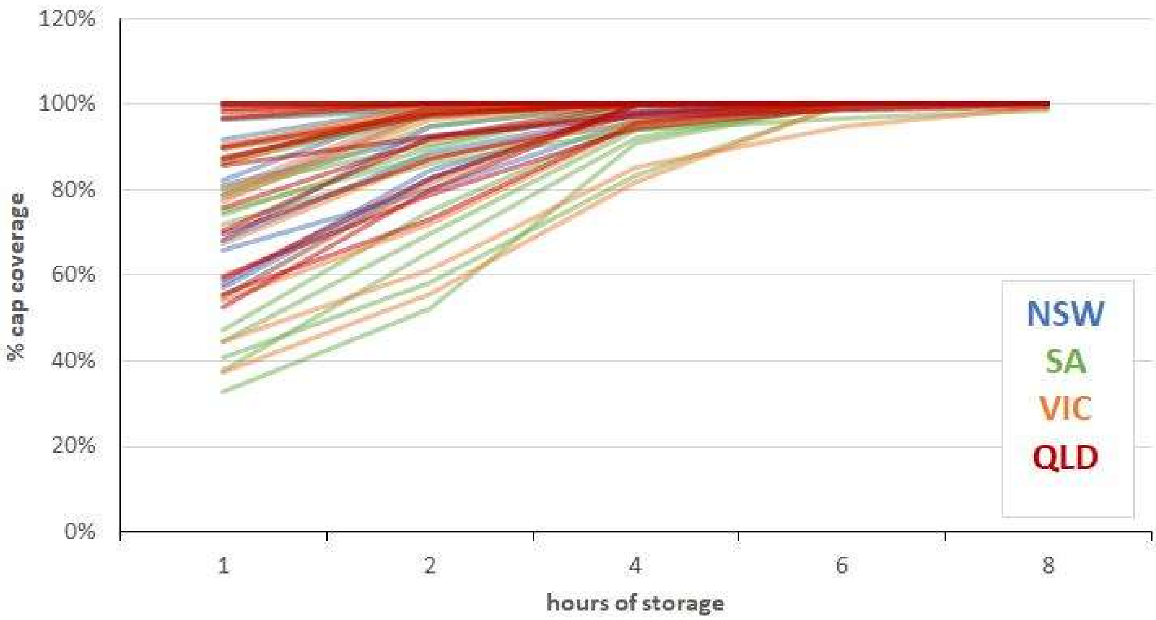
Appendix 1: Economics of battery storage in Australia's NEM today

There is currently ~750 MW of battery storage installed or committed in the NEM.[16] Given the gap between current installed capacity and future requirements, storage appears to be a comparatively low risk firming technology, even excluding its value in frequency control services. Arguably, the largest risk is that of investing in technology with expected cost reductions.

Recent history also suggests that batteries are capable of delivering firming in the near-term. Figure shows the cap coverage[17] that of a hypothetical battery dispatched in each historical year from 2008 to 2021 with varying hours of storage. These dispatches are based on perfect foresight of half-hourly historical prices, solved in 17,520 hour steps, assuming the battery only operates in the energy market. An eight-hour battery would have been sufficient to pay out cap contracts in every year, but even a four hour battery would cover 80% of the cap payouts. In practice, batteries would not achieve perfect foresight, but this is true of all sellers of cap contracts, and shortfalls are reflected in both the premiums on the sale of cap contracts compared to payouts.

Figure A1: $300 cap coverage of a hypothetical battery (2008-2021)



[16] See AEMO Generation Information page - https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information, Accessed online on 13 January 2022.

[17] Defined as the revenue due to the component of price above $300/MWh (e.g., $150/MWh when wholesale prices are $450/MWh *and* the unit was generating) divided by the cap contract payout, being the sum of all price components above $300/MWh. "Undercap" revenue, from the prices below $300/MWh, is not included.