Go for net zero

A practical plan for reliable, affordable, low-emissions electricity

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Overview

Australia's National Electricity Market (NEM) can achieve net-zero emissions without threatening reliability or affordability.

Those who say coal-fired power will continue to be needed are wrong. Those who say Australia should commit to a 100 per cent renewable energy target now are also wrong. This report identifies the best path.

In 2020, Australia's electricity sector emissions, at 172 million tonnes, were 34 per cent of the nation's total. The Government's latest projections indicate they will fall to 111 million tonnes by 2030, 44 per cent below the level of 2005. This is a remarkable achievement, driven primarily by the growth in renewable energy, projected to reach 55 per cent of generation by the end of this decade.

The major federal political parties are committed to net-zero emissions. The current policy debate is focused on how to meet this target and ensure that a system dominated by intermittent wind and solar power can deliver acceptably reliable electricity. This report answers that question with the aid of a sophisticated economic model of the NEM. It provides an analysis of what the NEM could look like with higher levels of wind and solar electricity than today, and what the cost is likely to be compared with a system dominated by coal.

The analysis leads to three conclusions. First, Australia can move to 70 per cent renewables across the NEM with little risk to reliability or affordability. Achieving 90 per cent renewables will be slightly more expensive but will slash emissions at relatively low cost.

Second, as the proportion of renewables increases, the value of inter-regional transmission and an interconnected NEM grows, to ensure sufficient supply at times when less wind and solar energy is being generated. Battery storage, alongside gas-fired generation, will also play an important role in 'balancing' the system.

Third, the best information today indicates that achieving net-zero emissions in the NEM will be most efficient if a small and declining quantity of emissions are offset. The alternative – achieving absolute-zero emissions – looks more costly. As the proportion of renewables grows from 90 per cent to 100 per cent, the physical and economic challenge of balancing the system during rare, sustained periods of high demand, low wind, and cloudy skies becomes too big.

Gas generation with offsets looks to be the lowest-cost 'backstop' solution until zero-emissions alternatives – such as hydrogen-fired generation or near-perfect carbon capture and storage – are economically competitive. Gas is likely to play a critical, but not expanded, role: the NEM faces a gas-supported transition, not a 'gas-led recovery'.

Policy makers can be confident in planning for net-zero emissions. Governments should back current efforts, led by the Energy Security Board, to integrate renewable generation and storage with interstate transmission and renewable energy zones.

Net-zero emissions in the NEM is an appropriate policy target for the 2040s, given the importance of low-emissions electricity for decarbonising other sectors of the economy. 100 per cent renewable energy is too inflexible a target to set today, given that the economics look harder in the next few decades.

As Australia moves towards net-zero emissions across the economy, most likely in the 2040s, offsets will become increasingly expensive. Emissions-reduction policy and the electricity market framework will need to accommodate the technology developments that will best close the final gap to a real zero-emissions future for the NEM.

Recommendations

1. Pursue policies to reduce emissions in the NEM

Governments should pursue policies to reduce carbon emissions, confident that a high-renewables National Electricity Market (NEM) can be reliable and affordable. They should not use taxpayer funds to extend the life of existing coal-fired generators, or to subsidise the entry of new coal-fired generators.

2. For now, target ‘net-zero emissions’, not ‘zero emissions’ or ‘100 per cent renewables’

Governments should target net-zero emissions for the NEM for the 2040s, given the importance of low-emissions electricity for decarbonising parts of the transport and gas sectors. To reach this goal quickly and efficiently, governments should commit only to net-zero emissions, not to absolute-zero emissions or 100 per cent renewable energy targets.

3. Continue to support development and deployment of low-emissions technologies

Governments should plan for how and when to eliminate the last few per cent of emissions from the NEM. They should maintain support for developing zero-emissions firming technologies and closely monitor the relative economics of these technologies and negative-emissions offsets. They should facilitate the deployment of these technologies when it becomes clear that reducing emissions to zero is lower cost for consumers than using offsets.

4. Remain committed to the integrated NEM

Governments should re-commit to an interconnected NEM to deliver reliable, low-emissions electricity at lowest cost. They should resolve cost allocation disputes so interconnector upgrades that pass a rigorous cost-benefit test can proceed as needed. They should support the Energy Security Board (ESB) to develop a common approach to underwriting early work on high-priority interstate transmission, and implementing Renewable Energy Zones.

5. Implement policies to reduce emissions across the economy at lowest cost

A single, economy-wide emissions price would be the most efficient way to ensure that emissions in each sector are reduced at lowest cost. If that remains out of reach, then:

- Governments should at least cease direct intervention in the electricity market, and embrace the ESB’s resource-adequacy mechanisms combined with state-based renewable electricity mechanisms.
- Governments should pursue alternatives such as creating and trading Australian Carbon Credit Units between sectors, as a second-best policy to reduce the cost of maintaining sector-based emissions reduction programs.

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1 Australia needs clarity on the future of the National Electricity Market

Australia's National Electricity Market (NEM) is facing fundamental challenges. Coal remains the largest source of energy in the system, but Australia's coal-fired power stations are ageing and most are scheduled to be retired by 2040 (see Figure 1.1). Australia is also a signatory to the Paris Agreement on climate change, which means it has committed to reduce greenhouse gas emissions to limit global warming to well below 2℃, and preferably to 1.5℃, compared to pre-industrial levels. The Prime Minster has confirmed that the goal is net-zero emissions.

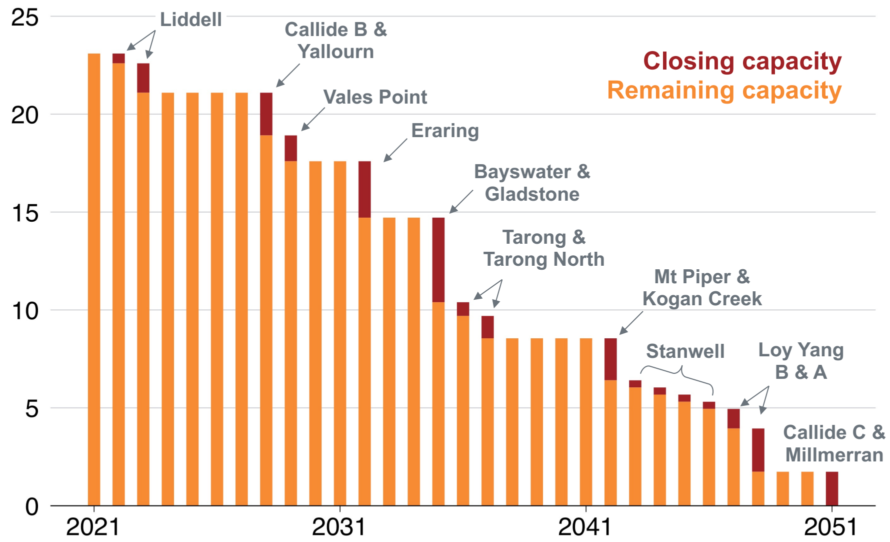
New sources of generation will be needed to fill the gap left by retired coal-fired generators. And emissions in the NEM have to fall if Australia is to meet its climate commitments. Wind and solar are obvious candidates for new generation, and they are being deployed rapidly. But there are legitimate concerns that increased reliance on wind and solar will make the electricity supply less reliable.

Policy makers at state and federal level disagree about what mix of new generation sources is needed, and how to ensure enough capacity is built in time to replace exiting coal. This is leading to uncoordinated policy action by different governments, which is unlikely to produce the lowest-cost outcome for Australians.

Australia needs clarity about the long-term future for the NEM. This would help policy makers to ensure households and business can continue to get reliable, affordable electricity, and governments can meet their climate commitments.

Figure 1.1: Most of Australia's coal-fired power stations are scheduled to be retired over the next few decades

Scheduled capacity, gigawatts



Note: No closure date has been announced for Callide C, but the Australian Energy Market Operator (AEMO) estimates it will close in 2051, based on the technical life of the plant: AEMO (2020a).

Sources: Grattan analysis of AEMO (2021a), AEMO (2021b) and EnergyAustralia (2021).

1.1 Coal closure and climate change are forcing the NEM to evolve rapidly

Coal remains the largest single source of electricity traded in the NEM, owing to its abundance and low cost. At the peak in 2009, there were more than 28 gigawatts (GW) of coal-fired generation capacity in the NEM.[1] But today there are only 23GW, and most of that is scheduled to be retired by 2040, with virtually all closed by about 2050. Meanwhile, more than 8GW of wind and 5GW of utility-scale solar have entered the market.[2]

Before there was a pressing need to reduce emissions, the design of the NEM solved the problem of retiring capacity. Most owners of generation assets in the NEM are private companies; they invested on a commercial basis. When a major plant closes, the supply of electricity is reduced, which increases the wholesale market price. This creates an incentive for investment in the most competitive new plant. In the absence of major technological breakthroughs, the replacement would usually be like-for-like. And in an effective market, the new supply would restrain prices.

But there have been technological breakthroughs – wind and solar are now the cheapest forms of bulk electricity.[3] And there is a pressing need to reduce emissions: global action on climate change is overwhelmingly in Australia's national interest.[4] All states and territories have committed to achieving net-zero emissions by 2050, and the Prime Minister hopes this timeframe can be met.[5] In practice, this means that by 2050 all sources of electricity in Australia will need to be either zero-emissions (such as wind, solar, hydro, biomass, hydrogen, or nuclear)[6] or – if the electricity is produced from fossil fuels – the emissions will need to be offset[7] or captured and buried.[8]

This makes replacing retired capacity much more complex. The NEM is being transformed: the mix of generation sources is changing, with renewable energy displacing fossil fuels. This is creating several challenges (see Box 1 on the following page). It is also the major reason emissions have fallen across the NEM from a peak of 187 million tonnes (Mt) in 2009 to 142Mt in 2020.[9]

1.2 Renewable energy is part of the solution, but it has an Achilles' heel

At face value, the obvious way to replace retired coal plants and reduce emissions is to build more renewable energy. Solar and wind are now the cheapest forms of bulk electricity, cheaper per unit of electricity than coal – a remarkable shift from a decade ago.[10] That's good for affordability. And these forms of energy are renewable: they won't run

1. AEMC (2020a, Figure 2.3). The NEM today has about 50GW of generation capacity, but peak demand has never exceeded 36GW: AER (2020).
2. Throughout this report, references to 'solar' imply solar photovoltaic (PV) technology. These are panels which convert sunlight to electricity. Alternative forms of solar generation, such as concentrated solar thermal (where sunlight is used to heat a substance to drive a turbine) do not produce electricity nearly as cheaply as solar PV, and have not been commercially deployed in the NEM: Graham et al (2020a).
3. Graham et al (2020b, p. viii).
4. Wood et al (2020, pp. 5–8).
5. Wood and Dundas (2020, p. 8) and Morrison (2021). In February 2021, Scott Morrison said: 'Our goal is to reach net-zero emissions as soon as possible, and preferably by 2050.'
6. Nuclear power generation in Australia is prohibited by legislation: *Environment Protection and Biodiversity Conservation Act 1999*.
7. This means that for each tonne of emissions produced, one tonne of emissions is drawn down from the atmosphere and permanently stored – possibly as biomass (in trees and plants), in the soil, or underground. See Box 7 on page 37 for more details.
8. This is referred to as carbon capture and storage (CCS).
9. DISER (2020a).
10. Graham et al (2020b, p. viii).

Box 1: Other challenges facing the NEM outside the scope of this report

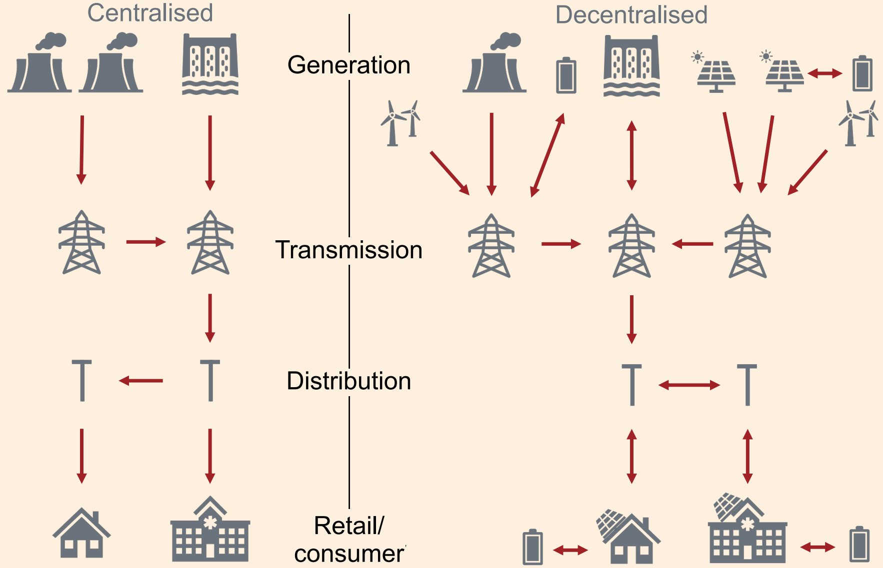
As wind and solar generate more of Australia's electricity, power supply is becoming increasingly decentralised. This poses technical challenges beyond those explored in this report.

Historically, power was generated at a small number of large power stations, transported to cities and towns via the transmission network (the tall, metal-frame towers), then transported to households and businesses via the distribution network (the poles and wires on the street). Most consumers purchased all of their power from a retailer. But that story is changing.

On the generation side: big coal- and gas-fired generators are being retired, and replaced by a larger number of smaller renewable generators – often at far-flung corners of the grid. The cost, reliability, and emissions implications of that change are discussed in this report. But there are technical challenges too. For example, thermal and hydro generators help to keep the system operating within certain technical limits (keeping the NEM 'secure'). With an increased reliance on renewable projects, the Australian Energy Market Operator (AEMO) will need to change the way it manages the grid to ensure the system remains secure.[a] Replacing these essential system services is a high priority.[b]

On the consumer side: increased rooftop solar and battery uptake means the flow of electricity is no longer just one way. Consumers can now produce, store, and export their own power to the grid. This is creating problems for the distribution network, which was not designed with two-way flows of power in mind.[c] AEMO is working to resolve the looming problem of negative demand, which will occur when the output from rooftop solar is greater than the demand and export capacity of a state.[d]

Figure 1.2: Renewables and storage, both at the household and utility-scale, are making power more decentralised



Source: Grattan analysis.

a. AEMO (2020b, pp. 4–8). We don't aim to solve system security issues in this report, but do include a high-level estimate of the cost involved.
b. Both the Energy Security Board (ESB) and the Australian Energy Market Commission (AEMC) are working on this urgent issue: ESB (2021) and AEMC (2020b).
c. AEMO (2020b, pp. 38–40). The distribution network is not analysed in this report.
d. AEMO (2020c).

out, and they produce zero carbon emissions. Australia is blessed with globally-significant wind and solar resources.[11]

But their output varies depending on the time-of-day and the weather. This has implications for the reliability of electricity supply. Electricity is an essential service that, unlike most other commodities, cannot be easily stored for extended periods or quickly sourced from elsewhere if there is a shortage. That means the system must be designed to minimise the risk of shortages – in the NEM, governments expect that 99.9994 per cent of consumer demand should be met each year.[12]

To maintain reliability, solar and wind (which are described as 'variable renewable energy' or VRE) must be balanced, or 'firmed', typically with 'dispatchable' electricity sources such as coal, gas, hydro, or batteries. The output of these technologies can be readily ramped up and down – though not equally as quickly. Coal is much slower to ramp than fast-start gas generators, which themselves are slower than batteries.[13]

But there are also other ways to help firm variable renewable energy. For example, electricity users could be rewarded for reducing their demand when supply is tight (known as 'demand-side participation' or DSP). Or substantially more wind and solar capacity could be built in parts of the NEM which tend to be windy or sunny when other large parts of the NEM are calm or cloudy. The NEM covers most of eastern Australia (Figure 1.3 on the next page), so it's rare for renewable output to be low *everywhere* across the NEM at the same time. With more transmission connections, areas with high renewable output in any given hour could help areas with low output in that same hour.

'Firming' adds to the cost of supplying electricity. And the more wind and solar in the system, the more firming is required.[14] This means that adding more cheap renewable energy assets to the NEM won't necessarily reduce the overall cost of providing electricity.[15]

1.3 Without clarity on the future of the NEM, policy action has been haphazard

Australian governments want to move to a low-emissions electricity system while keeping power reliable and affordable. But they differ on how to get there. The result is uncoordinated and even contradictory policies and interventions.

Governments are anxious to avoid their worst-case scenario: a substantial shortfall in supply leading to significant blackouts.[16] To date, such events have been rare. Occasionally, the combination of hot weather and unexpected plant outages has forced the market operator to temporarily suspend supply to parts of a state on a rolling basis.[17] But the vast majority of blackouts are caused by disruptions in the distribution system.[18] That is, there's enough power to go around, but

11. Wood et al (2020, p. 14).
12. This level is known as the 'Interim Reliability Measure'; it was introduced in 2020 to help ensure that the NEM's Reliability Standard of 99.998 per cent is met 9-in-10 years on average: COAG Energy Council (2020). Achieving even greater reliability would require significant over-investment in the infrastructure that supplies electricity, and would be unacceptably costly to consumers: Wood et al (2019a, p. 11). A 100 per cent reliable system is not realistically possible.
13. AEMO (2020a); and Aurecon (2019).
14. Graham et al (2020b).
15. Some commentators such as Finnigan (2021, p. 4) assume that 100 per cent renewable systems must be the lowest-cost configuration because wind and solar are so cheap; this is not a sensible conclusion, because it neglects the cost of firming.
16. Separate to reliability (or 'resource adequacy'), governments also worry about a catastrophic technical failure (a loss of 'system security') that would prevent the electricity system from functioning at all. If reliability is about whether *all* demand can be met, security is about whether *any* demand can be met.
17. For example, on 25 January 2019 more than 200,000 Victorian customers had their power interrupted on a rotating basis between midday and 3pm; it was 43℃ and three coal units were offline: Wood et al (2019a, p. 14).
18. Ibid (p. 10).

no line capacity to transport it – either due to maintenance, a technical failure, or a storm or car accident knocking over a power pole.

Despite the rarity of blackouts caused by supply shortfalls, governments have increasingly intervened in the market in an effort to reassure customers about reliability.[19]

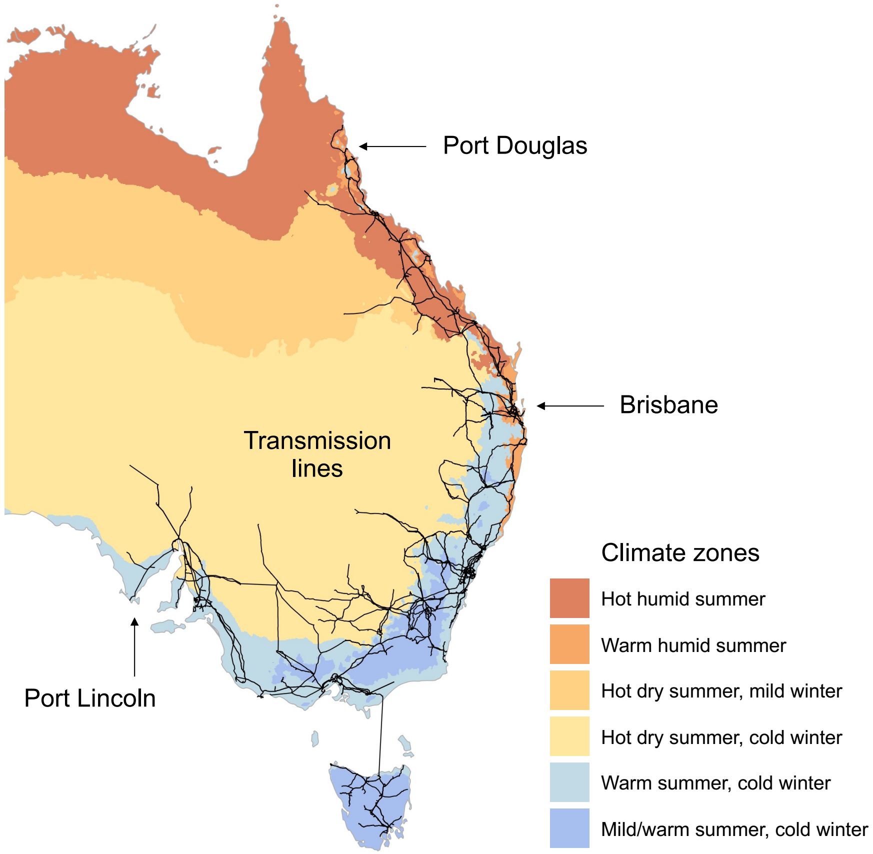
The fate of the Liddell coal-fired power station in the Hunter region of NSW offers one such example. After AGL notified the market in 2015 that it intended to close the ageing plant by 2022, the Federal Government took several measures to deal with what it perceived to be a threat to reliability:

- Then Prime Minister Malcolm Turnbull pressured AGL to extend Liddell's life or sell the station to another operator.[20]
- Even after AGL agreed to delay the full closure by a year to 2023, Energy Minister Angus Taylor established a taskforce to investigate options for extending its life or replacing it 'like for like'.[21]
- The Federal Government subsequently said the private sector would have to deliver 1,000MW of dispatchable capacity in the Hunter before the plant closed, or the Government would ensure that the gap was filled by using the government-owned Snowy Hydro corporation to build new gas capacity.[22]

These actions were taken despite AEMO forecasting that only 154MW of additional capacity would be needed in NSW by 2023-24.[23]

19. Several examples of government interventions since 2016 are outlined in Wood et al (2019b, pp. 7–10).
20. Turnbull (2018).
21. Taylor (2019).
22. Morrison and Taylor (2020).
23. AEMO (2020d, p. 9). This extra capacity is needed only to meet the stricter 'Interim Reliability Measure' introduced by energy ministers in 2020: COAG Energy Council (2020). Under the existing Reliability Standard, no additional capacity would have been needed.

Figure 1.3: The NEM covers many different climates



Source: Grattan analysis of BOM (2021) and Geoscience Australia (2015).

The NSW Government has taken a very different but equally interventionist approach. It has developed its own Electricity Infrastructure Roadmap to ensure 12,000MW of renewable energy and 2,000MW of long-duration storage enter the market by 2030.[24]

These direct interventions in the market are creating an uncertain policy environment, making it harder for private investors to commit to new projects. In response to the NSW Government's roadmap, AGL deferred its final investment decision on a new gas-fired power station near Newcastle. AGL's Chief Financial Officer Damien Nicks said:

> The recent announcement by the NSW Government of their energy roadmap means that we will need to pause this acceleration and defer FID [final investment decision] until we understand the detail that sits behind the announcement and the legislation that is before the Government.[25]

EnergyAustralia also delayed its decision on the proposed Tallawarra B gas-fired power station on the NSW south coast. EnergyAustralia's Energy Executive Liz Westacott said:

> It is very hard to balance all the variables. There's so many variables that we have to contemplate – the role of Liddell itself, the role of Snowy, and the Federal Government announcement [and] State Government announcements.[26]

The Australian Energy Council, which represents the largest Australian electricity generators, warned that both the federal and state interventions had dampened investor confidence and made investment decisions more complex.[27]

24. NSW Government (2020). Long-duration storage is capable of dispatching its nominal capacity for at least eight hours.
25. Macdonald-Smith (2020).
26. Macdonald-Smith and Ludlow (2020).
27. AEC (2020a); and AEC (2020b).

1.4 Sensible debate about the long-term future of the NEM requires a better understanding of the feasible alternatives

Some Australian politicians argue that only new coal can deliver reliable, cheap power.[28] Others point to the cheap cost of solar and wind to argue that the best way to drive down costs is to move rapidly to 100 per cent renewable energy.[29] Both extremes are wrong.

Governments need to understand the likely trade-off between cost and reliability, and what challenges are likely to emerge on the path to net zero. This report identifies several possible configurations of generation and transmission assets that could enable the NEM to deliver reliable, low-emissions power. Some technology mixes will be cheaper than others, enabling Australia to meet its decarbonisation goals while keeping costs as low as possible for consumers.

For this report, Grattan Institute developed an economic model of the NEM (see Box 8 on page 47) to understand how a system with high levels of renewable generation can deliver acceptable reliability, what supporting technologies and infrastructure are required, and what the costs could be compared to a system that continues to be dominated by coal. To do so, we analysed the supply mix that would meet demand in 2040, given historical demand and weather patterns. For detail on how we constructed the model, see Appendix A.

The next chapter considers two questions governments are debating today: whether coal has a future in the NEM, and whether a renewables-based system can deliver reliable electricity at reasonable cost. It compares three scenarios: a low-renewable future where the coal fleet is maintained and replaced; a 70 per cent renewable future, with much less coal and much more wind and solar; and a 90 per cent renewable future, with no coal at all.

28. See, for example: The Nationals (2021, pp. 17–19).
29. See, for example: The Greens (2021).

Chapter 3 looks further ahead, considering how best to reach net-zero emissions. It analyses the cost implications of using different technologies to boost the share of renewable energy in the NEM. And it explores the value of using negative-emissions offsets to meet a net-zero target.

Chapter 4 identifies what governments should and should not do today to hit their their long-term climate targets while maintaining reliable, affordable electricity supply.

2 Switching from coal to renewables is a cost-effective way to reduce emissions

As ageing coal-fired power stations are retired over the next few decades, Australia has an opportunity to replace them with lower-emissions sources of electricity. But governments are also under pressure to ensure the electricity supply is reliable and affordable. The Federal Government is debating whether retired coal plants should be replaced with more coal, more gas, or renewables.

This chapter compares the long-run costs of three, reliable electricity systems. In the first scenario, today's coal capacity is maintained, and renewables supply less than 30 per cent of electricity in the NEM. In the second scenario, renewables replace most of the coal capacity to deliver about 70 per cent of the electricity. The third scenario looks further ahead, considering the implications of eventually ending all coal-fired generation and using renewables to supply more than 90 per cent of electricity.

In comparing these scenarios, it becomes evident that governments have little to fear from moving to a mostly-renewable system. The first two scenarios deliver electricity at similar cost, but the renewables-based system produces less than half the emissions. And the third scenario – a near-total renewable system with zero coal – is likely to be a cost-effective way to further reduce emissions, despite the additional costs of 'firming' very high levels of wind and solar electricity.

2.1 Comparing three scenarios for the NEM

To better understand the challenges associated with moving to a renewables-based system, and how costly it might be to solve them, we've analysed three scenarios:

- A **'keep coal'** scenario, where retired coal-fired generators are replaced 'like for like' by equivalent-capacity, new coal-fired power stations,[30] and where renewable electricity sources (including hydro) make up less than 30 per cent of all generation;[31]
- A 70 per cent renewables scenario (**'70%RE'**), where about two-thirds of coal generators[32] are retired and are replaced primarily by renewable electricity and storage;[33] and
- A 90-plus per cent renewables scenario (**'90%RE'**), where all coal generation is assumed to exit the market, so only renewables, storage, and gas provide the NEM's electricity.

The generation mix for each scenario is shown in Figure 2.1 on page 15. In the 'keep coal' scenario, the total coal capacity is about 23GW – similar to today. In the '70%RE' scenario this falls to about 8.5GW, and in the '90%RE' scenario there is no coal. Each scenario also has significant amounts of variable renewable energy and dispatchable capacity, with interstate transmission and utility-scale batteries playing increasing roles as the renewable share grows. These

30. These new stations would be lower-emissions than existing plants, but would still produce substantial carbon pollution, requiring significant amounts of offsets or additional carbon capture and storage (CCS) infrastructure to get to net zero in the long run. CCS was not explicitly modelled, but its economics are discussed in Section 3.2.5 on page 33.
31. The share of renewable electricity refers only to electricity generated for trading in the NEM, not including generation from storage. It also does not include rooftop solar, which is assumed to provide the same amount of electricity in each scenario, with uptake driven by consumer preferences. See Appendix A.1.3 on page 50 for more details.
32. In the model, any coal generator planned to be retired by 2040 exits the market; remaining coal generators are assumed to be replaced 'like for like' at the end of their lives. This models an incomplete move away from coal.
33. A 'coal to gas' scenario was also tested, but the high running costs of using gas make it a very expensive way to supply the bulk of electricity in the NEM.

generation combinations are the approximate least-cost mixes needed to ensure reliable supply (see Box 2).[34]

Figure 2.2 on the following page compares the total electricity generated by each technology, averaged across nine years of historical weather and demand patterns.[35] In the 'keep coal' scenario, coal provides more than 130 terawatt-hours (TWh) of electricity per year – about 70 per cent of all electricity.[36] Gas meets a very small share of the electricity demand; this is partly because coal is assumed to be able to ramp freely between its minimum and maximum stable output each hour.[37] In reality, gas could play a slightly larger role due to its greater flexibility, partly reducing coal's share of electricity production.

In the '70%RE' scenario, coal supplies less than 50TWh, while wind and solar provide more than 125TWh each year. Some of this electricity is used for storage rather than to meet consumer demand directly. Renewable electricity – including hydro – makes up about 70 per cent of all generation.[38] Coal, gas, hydro, and storage all help to balance, or 'firm', the variable renewable energy supply.

34. The generation mixes are only approximately least-cost due to the optimisation methodology employed (Appendix A); deviations from the hypothetical least-cost outcome are expected to be small enough that the overall conclusions drawn in this report remain robust.
35. This report uses projections of demand, wind, and solar availability for the year 2040 based on historical patterns, produced by AEMO (2020e). Grattan's model tests each scenario against nine possible versions of 2040, each based on a year of historical data, to ensure the system is reliable in a wide range of operating conditions. See Appendix A.
36. A terawatt-hour is 1,000 gigawatt-hours, or 1 million megawatt-hours. Storage is not counted as a form of generation when calculating what percentage of demand is met by a specific source, such as renewable energy or coal.
37. See Appendix A.2 on page 53 for more details.
38. On average, 72 per cent across the nine modelled years.

Box 2: The Grattan model estimates the long-run cost of supplying electricity; it does not forecast prices

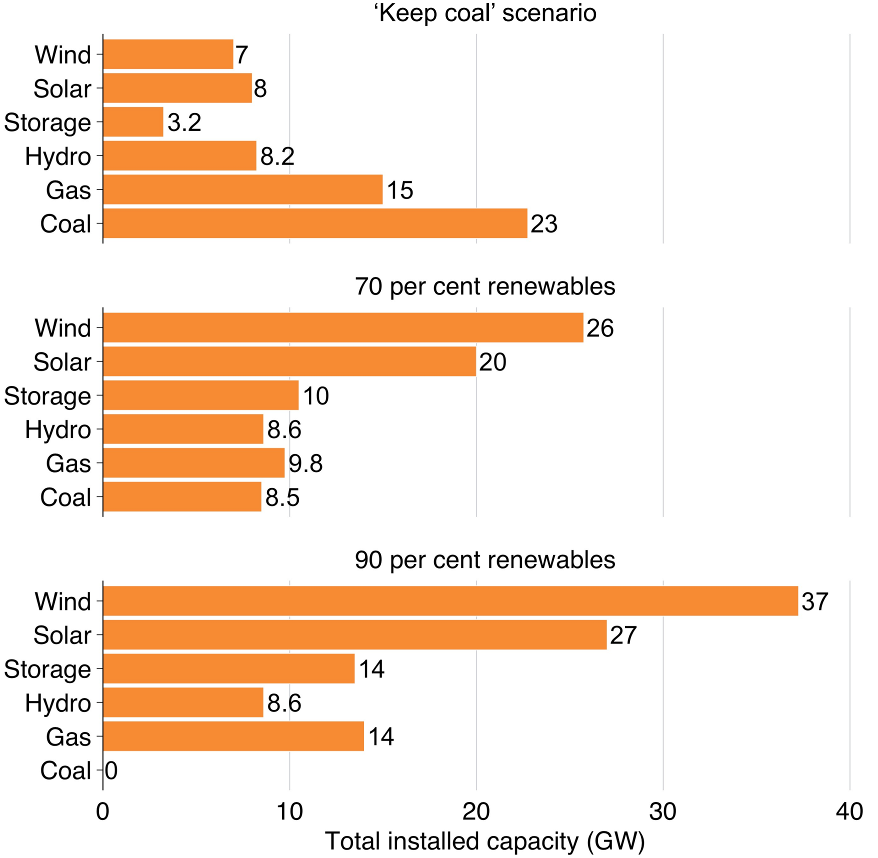
The Grattan model calculates the cost of supplying electricity in dollars per megawatt-hour of consumer demand ($/MWh), which we describe as the 'system unit cost'.[a] While the wholesale electricity price is also measured in dollars per megawatt-hour, the model does *not* forecast prices.

One obvious reason the system unit cost is different to the wholesale price is that the cost of building new transmission is included in the system unit cost. Consumers do not pay for transmission via the wholesale price of electricity; they pay via network charges, which are added to their bill separately. Transmission costs vary between scenarios.

The system unit cost provides some insight into the future direction of prices, without offering a specific forecast. This is because in a competitive, well-functioning market, average volume-weighted prices should reflect the underlying cost of supplying electricity over the long run.[b] The NEM is not perfectly competitive however, so inferences about price should be treated with caution. And prices are also cyclical in practice, fluctuating above or below the system unit cost depending on whether the market is over- or under-supplied.[c]

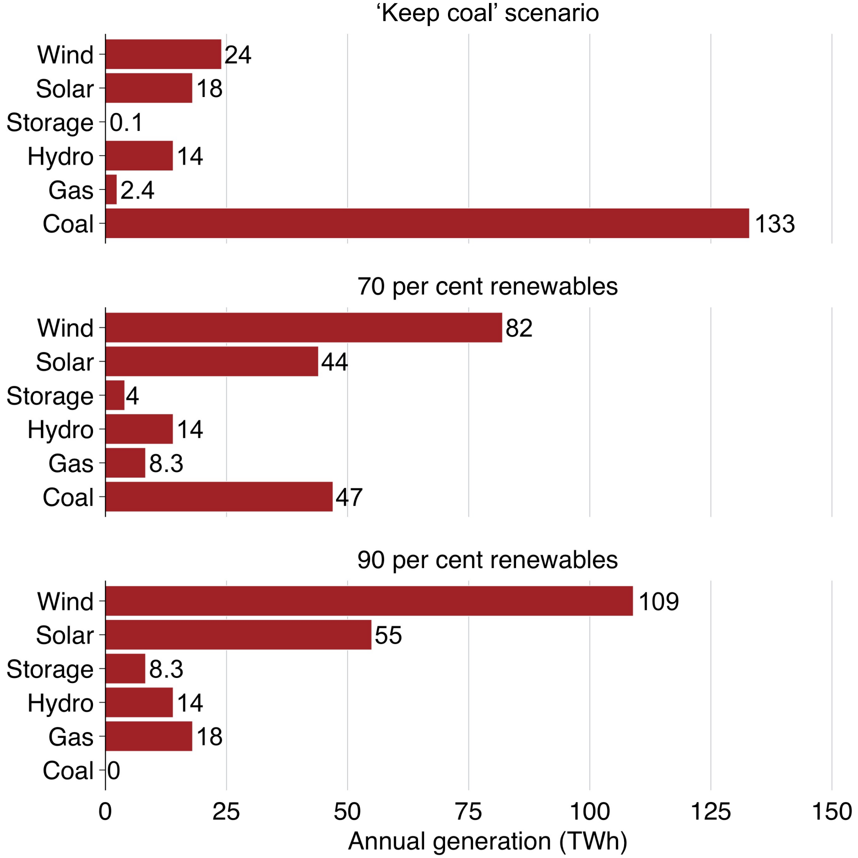
a. This is also known as the 'levelised system cost': it is the annual cost of building and operating assets divided by the annual consumer demand they meet. See Appendix A.3 on page 55 for more details.
b. Nelson et al (2018).
c. Prices can also remain below the cost of supplying electricity if generators receive revenue from other sources, such as government subsidies or favourable contracts.

Figure 2.1: The three scenarios have different balances between coal, renewables, and other technologies
Capacity by scenario



Notes: See Figure A.2 on page 49 for state-specific capacities. The hydro capacity of all states except Tasmania is assumed to remain the same as today (see Appendix A.1.1 on page 46 for details). The total energy available from hydro has been reduced due to projected climate impacts: AEMO (2020a).

Figure 2.2: Less coal capacity means less coal generation; wind and solar fill the gap, firmed by other technologies
Annual generation by scenario



Note: Annual generation is the average over the nine modelled years.

In the '90%RE' scenario, wind and solar supply more than 160TWh on average each year.[39] With no coal in the system, there is a slightly larger role for gas in balancing renewable output (compared to the other scenarios), alongside storage and hydro. The amount of gas used is no larger than historical levels: it ranges from 95-to-195 petajoules (PJ) per year depending on the demand and weather patterns in the modelled year. In comparison, gas-powered generation consumed between 127 and 220PJ per year over 2010-2020.[40]

2.1.1 Comparing interstate transmission

Our analysis tested two interstate transmission configurations (Table 2.1).[41] The first keeps interconnector capacities the same as today; the second is an upgraded configuration, which increased the capacities significantly by including a suite of potential network upgrades considered by AEMO in its 2020 Integrated System Plan (ISP).[42] The modelled upgrades comprise the Project EnergyConnect link between SA and NSW,[43] the 'QNI Medium and Large' Qld-NSW upgrades, the 'HumeLink' and 'VNI West (Shepparton)' upgrades to the Vic-NSW capacity, and the 'Marinus Link' project to install two additional 750MW cables between Victoria and Tasmania.

39. Including hydro, renewable electricity makes up about 91 per cent of all generation on average.
40. AEMO (2021c, Figure 15).
41. Within states, additional transmission to renewable energy zones (REZs) was built as needed to accommodate the specific wind and solar capacities. These were assumed to be separate connections from interstate links (see Figure A.3 on page 50), to avoid modelling congestion on either network – a conservative assumption that may somewhat undervalue interconnector upgrades.
42. The suite comprises all interconnector upgrades that AEMO has determined might be needed by 2040, depending on ISP scenario: AEMO (2020e, p. 64).
43. Instead of modelling a direct SA-NSW link, the model assumes a SA-Vic-NSW connection consistent with AEMO (2019a, p. 56), with the SA-NSW link capacity added to each of the SA-Vic and Vic-NSW capacities (see Figure A.3 on page 50 for a stylised representation of the transmission network used in the modelling).

The analysis in this report does not test alternative combinations of transmission or seek to evaluate the merits of any individual project. It aims only to test under what conditions more interstate transmission can help reduce the cost of delivering reliable electricity.

In the 'keep coal' scenario, keeping the interstate transmission network resembling today's network is a lower-cost option than investing in the upgraded interstate transmission. But for the '70%RE' and '90%RE' scenarios, the upgraded network offers better value, reducing the cost of electricity overall, despite the additional cost of the upgrades. States are able to support each other to a greater extent, reducing the need for in-state dispatchable capacity. Less wind and solar energy is wasted

Table 2.1: Interstate transmission capacities used in the Grattan model

Origin	Destination	Today's capacity (MW)	Upgraded capacity (MW)	Upgrade capex ($m)
Qld	NSW	1,302	3,664	3,260
NSW	Qld	657	2,877	
NSW	Vic	1,350*	3,000*	5,820
Vic	NSW	1,600*	3,600*	
Vic	SA	870	1,520	– (see notes)
SA	Vic	765	1,665	
Tas	Vic	594	1,978	3,155
Vic	Tas	478	1,728	

Notes: (*) The Vic-NSW interconnector capacity is reduced when the Snowy Hydro scheme is generating (see Appendix A.1.2). The modelling in this report sums the capacity of each interconnector between regions. The planned SA-NSW Project EnergyConnect link is modelled as two separate links, one between SA and Victoria, and one between Victoria and NSW. The cost is included in the cost of Vic-NSW upgrades. The capital cost of upgrades is assumed to be the same cost as used in AEMO's modelling for the 2020 ISP; see Appendix A.4.3 for sensitivity analysis.

Sources: AEMO (2017), AEMO (2020f) and AEMO (2020a).

– more of a state's excess supply can be exported to displace costlier forms of generation elsewhere in the NEM.

The benefit of the suite of transmission upgrades increases as the renewable share grows. In the '70%RE' scenario, including the upgrades reduced the system unit cost marginally,[44] suggesting that the links pay for themselves. But in the '90%RE' scenario, the upgrades reduced the system unit cost by about $5/MWh, indicating that more interstate transmission will be essential if renewable energy is to reach high penetration levels at lowest cost.[45] This result demonstrates the value of an interconnected NEM.

2.1.2 Comparing system reliability

The capacity mixes in each of the scenarios were chosen so that there is no unmet demand over the nine modelled years.[46] They also satisfy a prescribed capacity buffer – in every hour, there is sufficient spare capacity in the NEM (either within the state or by using interstate transmission) to ensure that about 15 per cent additional load can be met within any one state. This allows for unexpected plant outages; we do not explicitly model the effects of random technical failures of generators.[47]

Figure 2.3 on the next page shows how rarely a region in the NEM comes close to breaching the 15 per cent buffer requirement.[48] It shows that tight supply-demand balances are rare. This means a lot of infrastructure is rarely used – the systems are 'overbuilt'. But this is necessary if the aim is to minimise the risk of blackouts.

The Grattan model shows that the coal-based system runs on slightly thinner capacity margins most of the time. This is because the capacity of that system doesn't vary much each hour – there's just not that much wind and solar capacity in the scenario. The shape of the buffer curve is determined mostly by variability in demand, not variability in supply. In about half of the modelled hours, the lowest capacity buffer is below 100 per cent (i.e. the most constrained state could not cope with a sudden doubling of demand).

In the '70%RE' and '90%RE' scenarios, the capacity available each hour is more variable due to the higher penetration of wind and solar. To manage this, more overbuilding is necessary. That means there is even more time when the system has surplus capacity – it's rare for any state's hourly capacity to be less than double the state's demand. Nonetheless, this is the most cost-effective way to reduce the risk of shortfalls on the rare occasions when wind and sunlight are scarce and demand is high.

The fact that the '70%RE' and '90%RE' systems operate reliably despite their dependency on variable renewable energy demonstrates that the NEM does not need 'baseload' coal-fired generation to maintain reliability. 'Baseload' does not mean 'reliable' – it is an economic concept only (Box 3 on the following page).[49]

44. The difference was less than $1/MWh.
45. This finding implies that the upgraded transmission network would reduce system unit cost at 90 per cent renewables even if the upgrades cost 80 per cent more than assumed: see Appendix A.4.3 on page 57.
46. This is a more conservative approach than allowing some share of demand – such as 0.002 per cent (the Reliability Standard) – to go unmet. Yet this does not mean that the capacity mixes would be perfectly reliable in the real world.
47. There are engineering techniques that can model technical failure, but our economic modelling does not do so. Our analysis focuses on the 'resource adequacy' aspect of reliability because this is of particular concern to governments (Section 1.3 on page 9).
48. The regions of the NEM correspond largely to each state's boundaries, with the ACT forming part of the NSW region.
49. Wood et al (2019a, p. 19).

Box 3: Don't we need baseload power?

The short answer is 'no'.

Consumer demand for electricity used to follow a simple pattern: it was higher during the day and lower overnight. The economically-efficient way to satisfy that demand was to use low-cost coal for 'baseload' power, and more expensive gas, diesel, or hydro for 'peaking' power, whenever demand exceeded the baseload level.

But today, the concept of 'baseload' is becoming irrelevant. Demand patterns have changed significantly due to the uptake of rooftop solar, which is cutting NEM demand during the day. Before the end of the decade, it's very likely that in some states on some days there won't be any demand at all for hours at a time, because rooftop solar will supply more energy than the state needs.[a]

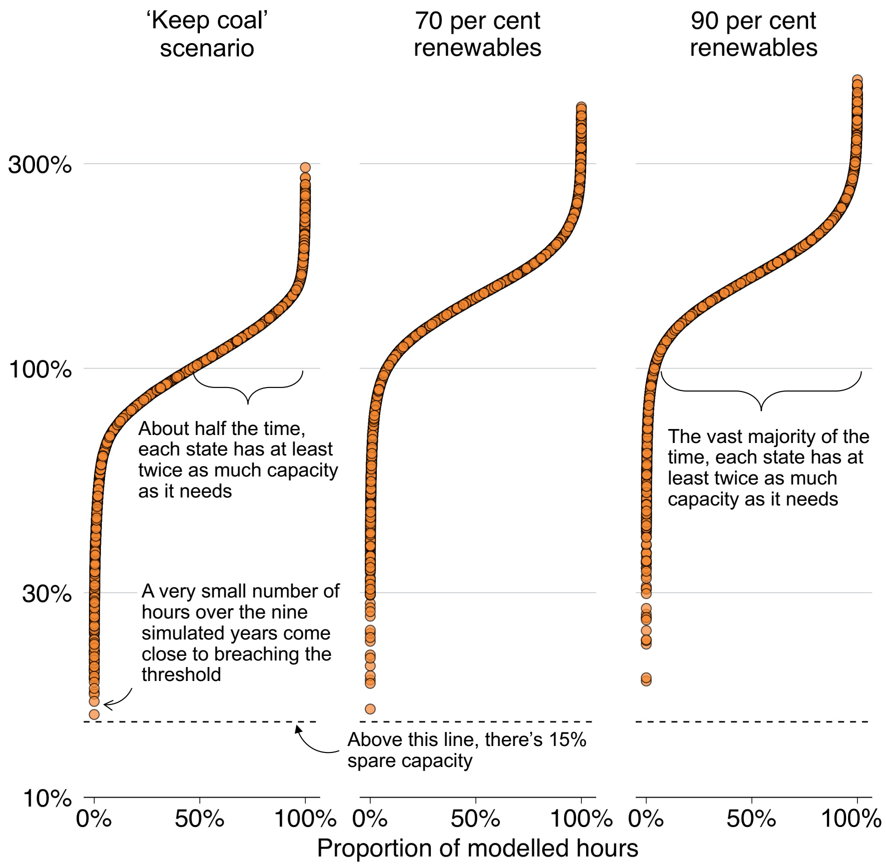
Supply patterns are also increasingly influenced by the availability of wind and sunlight. As more renewables enter the system, there is less 'baseload' demand left for traditional coal-fired generators to satisfy. This undermines the economics of coal-fired generators: they are most efficient when running at high levels of output for long periods of time. Ramping up and down, or switching off, means more wear-and-tear, lower efficiency, and fewer units of energy produced – so less revenue.

Under a renewables-based system, most electricity will be supplied by wind and solar, with the residual demand being highly variable and needing fast-acting power sources to balance it. This naturally favours 'peaking' generators, rather than coal.

a. AEMO (2020d, pp. 9–10).

Figure 2.3: Grattan's analysis shows there's excess capacity most of the time, especially as the renewable share grows

Extra available capacity relative to demand, log scale (one dot is one modelled hour)



Notes: 78,840 hours were modelled (nine versions of the 2040-41 financial year). Each dot represents the spare capacity in the state with the lowest buffer that hour. A buffer of 15 per cent means that there is enough energy available within the state and interstate (subject to transmission limits) such that even if 15 per cent of the state's capacity failed in that hour, there would be no unmet demand.

2.1.3 Comparing system unit costs

There are several conservative modelling assumptions that push up system unit costs for renewables-based systems,[50] including no financial value on emissions and no 'carbon risk' premium for coal- or gas-fired generation.[51] Yet the costs of the 'keep coal' and '70%RE' systems are nearly equivalent, while the '90%RE' scenario is slightly higher cost albeit with the lowest emissions by far (Section 2.1.4 on page 21).[52]

In all three systems, recovering the capital costs of generation assets is the largest contributor to the overall cost of supplying electricity (Figure 2.4 on the following page). The fossil fuel variable operations and maintenance costs are also large contributors – this category includes the cost of the coal and gas fuel inputs.

The two higher-renewables systems save on fuel costs compared to the coal-based system, but require expenditure on more storage, transmission, and 'syncons' (synchronous condensers): machines that provide inertia and system strength for the grid. These services traditionally come from coal, gas, or hydro plant – any large turbine that spins at the same frequency as the electric current in the grid. With less coal and gas capacity in the scenario, it is necessary to estimate the amount of syncons needed to fill the gap, and factor them into the total system unit cost; this adds a modest 1 to 2 per cent.

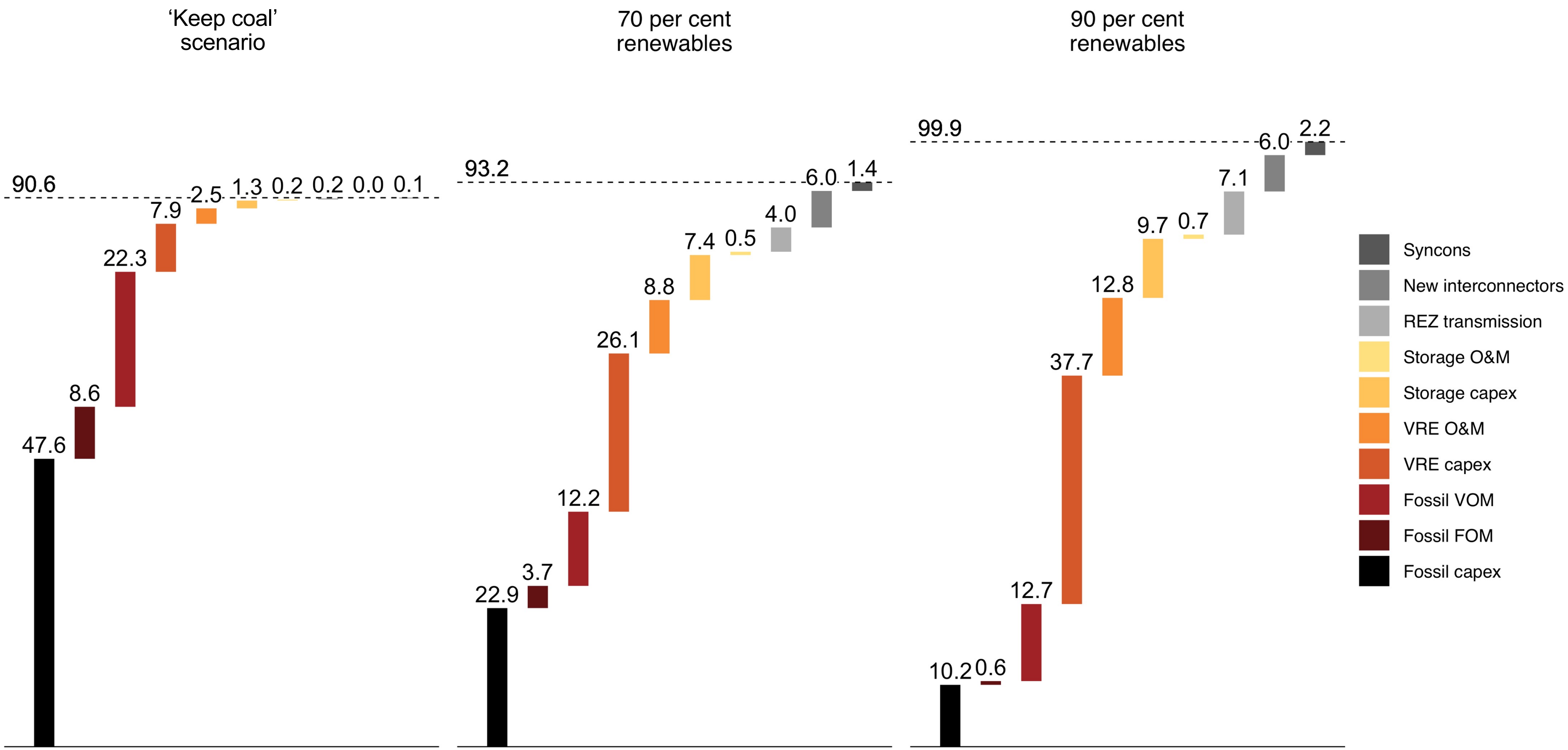
Short-to-medium duration storage is the most effective way to balance variable renewable energy over daily fluctuations in demand and supply.[53] Surplus energy, often during the day, can be used to charge batteries, which are then discharged to help meet peak demand on particularly challenging days.

Longer-duration storage options – pumped hydro projects with either 24- or 48-hours' worth of energy – were also tested, and do not reduce system unit cost relative to other firming options.[54] There are two likely reasons for this: first, the significant remaining coal and/or gas capacity in the high-renewables scenarios effectively offers low-cost long-duration firming, filling the role pumped hydro is intended to play; and second, storage operators were assumed to respond dynamically to market conditions rather than knowing in advance exactly what days and hours their energy would be needed.[55]

With better foresight, its possible that storage could deliver better value to the NEM. The potential for long-duration storage to overcome seasonal energy challenges is discussed in Section 3.1 on page 26.

50. See Section 2.2.2 on page 24 and Appendix A.4.1 on page 56.
51. Coal- and gas-fired generators are assumed to have the same financing costs as other technologies, ignoring the real-world risk that financial institutions believe these emissions-intensive types of assets carry (which would increase their financing costs): Chava (2014).
52. The difference in cost between the 'keep coal' and '70%RE' scenarios is about \$2.5/MWh, which is within the margin of error for this type of analysis. The '90%RE' scenario is about \$6.7/MWh higher-cost than the '70%RE' scenario. Both the absolute costs and the gaps between scenarios are likely to be even smaller in reality, given the conservative assumptions used in the modelling.
53. Short-to-medium duration spans 2-to-8 hours. Over these timeframes, batteries are more cost-competitive than pumped hydro: Graham et al (2020a, p. 26).
54. 24-hour pumped hydro was estimated to cost between \$3.1 million (NSW and Qld) and \$5.5 million (SA) per MW on the mainland. 48-hour pumped hydro was estimated to cost between \$3.7 million and \$5 million per MW, and was not available in SA. Storage options for Tasmania were not considered because that state's supply is already firmed by substantial existing dispatchable hydro capacity: AEMO (2020g).
55. Some electricity system modelling assumes generators have 'perfect foresight' – that they know the supply-demand balance or price for all modelled periods and can pick the best times to charge and discharge to either maximise profit or minimise the amount of capacity that needs to be built: Hydro Tasmania (2019). In Grattan's modelling, storage operators are assumed to respond to market conditions in a stylised way: decisions to charge, hold, or discharge electricity were made according to the supply-demand balance in that hour, over the next day, and over the next week, as well as how low a state's overall storage reserves were.

Figure 2.4: A mostly-renewable NEM would be cost-competitive with a mostly-coal NEM; but costs rise as the renewable share approaches 100 per cent
System unit cost ($/MWh)



Notes: ‘Syncons’ are synchronous condensers, which are increasingly used to provide system strength and inertia as the renewable share in the NEM increases (see Appendix A.3 on page 55). ‘REZ’ is a renewable energy zone – all wind and solar plant are built in REZs in this model. ‘O&M’ is operations and maintenance. ‘VRE’ is variable renewable energy. ‘VOM’ and ‘FOM’ are variable and fixed operations and maintenance costs respectively. VOM includes the cost of fuel. The absolute system unit cost values are sensitive to certain economic parameters, but the relative differences between scenarios are less sensitive (see Appendix A.4.2 on page 56).

We did not explicitly model the Snowy 2.0 pumped hydro project planned in NSW (see Box 4).

2.1.4 Comparing emissions

The biggest difference between the three scenarios is in emissions (Figure 2.5 on the following page). In the 'keep coal' scenario, where today's coal is assumed to be replaced with modern 'supercritical' coal plants, the emissions intensity of the NEM would fall by about 15 per cent, from 0.71 to 0.61 tonnes of emissions per megawatt-hour of demand (t/MWh).[56] The '70%RE' scenario shows that replacing most of the NEM's coal capacity with firmed renewables would cut emissions intensity by two-thirds to just 0.24t/MWh. That would reduce Australia's annual emissions by an extra 70 million tonnes (Mt) per year compared to the 'keep coal' scenario.[57] Eliminating coal and getting to 90 per cent renewable energy would further reduce the emissions intensity of the NEM to just 0.05t/MWh, or 10Mt per year on average.[58]

2.2 Implications for the future of the NEM

We draw three main conclusions from the analysis.

First, continuing to rely on coal as the major source of energy in the NEM will not keep prices as low as they are today. Moving to a renewables-based system probably won't either – the cost of a system

56. Grattan analysis of AEMO (2021d). These emissions-intensities refer only to electricity traded in the NEM – behind-the-meter electricity generation is excluded. Greenhouse gas emissions are typically measured in tonnes of 'carbon dioxide equivalents' (tCO_2-e). Any reference to tonnes of emissions in this report means tCO_2-e.
57. Annual NEM emissions in the 'keep coal' scenario are approximately 115Mt, compared to 45Mt in the '70%RE' scenario. A 70Mt per year reduction represents about 14 per cent of Australia's total emissions today (estimated to be 513Mt in 2020): DISER (2020a).
58. Annual emissions depend only on gas use in this scenario, which fluctuates significantly from year to year.

Box 4: What about Snowy 2.0?

Snowy 2.0 is a planned pumped hydro project that will link two existing dams in the Snowy Hydro scheme in NSW. When full, it will be able to discharge at 2GW for up to 175 hours.[a] The project is due to be completed in 2026.

Snowy 2.0 differs in two ways from the generic pumped hydro tested in this report.[b] First, its economics: Snowy 2.0 is expected to cost about $5 billion for 350GWh of storage, or about $14 million per GWh.[c] By comparison, energy storage from 48-hour pumped hydro plants in NSW is expected to cost about $77 million per GWh.[d]

The second difference is hydrological: the generic pumped hydro in this report is assumed to be a closed-system, so no water is lost or gained during operation. But Snowy 2.0 will interact with the existing Snowy scheme,[e] adding or taking water from dams involved in the production of traditional hydroelectricity. So accurate modelling requires a realistic representation of the network of dams. This report cannot claim to accurately depict the complex interactions that Snowy 2.0 will have with the existing Snowy Hydro scheme, so we have not modelled Snowy 2.0. But it is unlikely that its inclusion would fundamentally change the results of our modelling, given the large seasonal challenge in the '90%RE' scenario (which is explored in detail in Section 3.1 on page 26).

a. Snowy Hydro (2020).
b. Pumped hydro characteristics are taken from AEMO's Integrated System Plan: AEMO (2020a).
c. Letts (2019).
d. AEMO (2020a).
e. Snowy Hydro (2019, p. 9, S08).

underpinned by 70 per cent renewable electricity is comparable to that of a system reliant on coal. If prices rise in future, it won't be because the NEM is moving to renewables – it will most likely be because replacing ageing assets will be expensive, regardless of whether new coal or new wind and solar fill the gap.

Second, given that the cost of supplying most electricity using renewables is similar to using coal, making the coal-to-renewables switch is a 'no-regrets' choice to bring down emissions. Even a system with 90 per cent renewables or more would offer affordable opportunities for lower emissions.

Third, at high levels of renewables, the value of interstate transmission increases. All states benefit from the interconnected NEM even more than they do today.

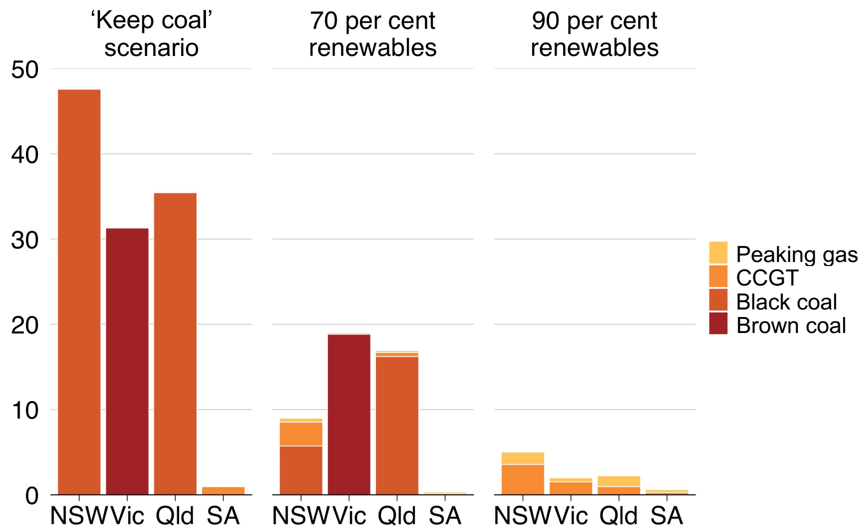
2.2.1 Replacing retired coal is expensive, and this will eventually flow through to prices

In the 'keep coal' scenario, where current coal capacity is assumed to be rebuilt with modern coal plants as it is retired, the system unit cost is \$91/MWh.[59] The cost of supplying electricity is not the same as the wholesale price, but the two concepts are related (see Box 2 on page 14). The cost of replacing legacy coal-fired generators is expected to eventually flow through to prices.

Some federal Coalition MPs believe building new coal-fired power stations would lower electricity prices.[60] While that is certainly not

59. As outlined in Appendix A, this cost includes the capital costs of each asset amortised over its economic life, using a weighted average cost of capital of 6 per cent. Changing either of these assumptions – for example, amortising over the entire technical life of the plant or using a different cost of capital – significantly changes the headline cost: see Appendix A.4.2 on page 56.
60. The Nationals (2021, pp. 17–18).

Figure 2.5: Less coal means fewer emissions
Annual emissions by source (Mt)



Notes: 'CCGT' is combined-cycle gas turbine, a more expensive but more efficient type of gas-power generation. In reality, slightly more gas and slightly less coal is likely to be consumed in the 'keep coal' and '70%RE' scenarios, because gas can ramp more quickly than coal, but this dynamic is not captured when using hourly data. Emissions include an allowance for fugitive emissions generated through fossil fuel extraction and transport: GHD (2018, p. 23). Tasmania has been excluded because it has no coal or gas capacity in any of the modelled scenarios.

the case,[61] existing coal-fired generators do offer relatively low-cost electricity without the intermittency of wind and solar. Coal is much cheaper per unit of electricity than gas,[62] and the supply of coal is generally less constrained than the supply of water in dams for hydro generation.

For a company operating an existing coal plant, the capital costs of the plant are 'sunk' – the company cannot get those costs back. So the rational strategy is to bid into the NEM at a price that will ensure the company recovers the cost of actually generating electricity: the cost of the coal, plus some operating costs.[63] That way, if the plant is required to produce energy, it won't lose money to do so. And if the regional electricity price exceeds the cost to operate, the generator makes a profit.[64]

Generation assets eventually wear out, forcing the company to make a decision: either invest more money to refurbish the plant, or close it. And the cost to refurbish will tend to grow over time: older assets have more technical failures and need more parts upgraded. Eventually, the refurbishment cost exceeds the value of the future cash flows from ongoing operation and the plant closes.

61. At least not if the new coal-fired power stations are built on a commercial basis. If new plants were to be sufficiently subsidised by governments, they could in theory drive down prices, but this would merely represent an unjustifiable transfer of value from taxpayers to electricity users.
62. AEMO (2019a).
63. Economists describe this as the 'short-run marginal cost': Nelson et al (2018). In reality, the generator may bid at higher prices if the market is not very competitive, 'shadowing' the short-run marginal cost of the next-most expensive generator. Or it may bid below its cost of production, either due to contract arrangements or because of technical limits on the plant's ability to ramp down or switch off. For a more detailed discussion of how generators bid into the NEM and set prices, see Box 9 on page 53.
64. This short-term profit does not guarantee profits over the longer term, because the company still has fixed costs to cover.

Plant replacement or major refurbishment requires a significant capital investment. To justify such investment, a company must expect that future revenue will be high enough to both pay for its short-run operating costs and recover its fixed costs – with an acceptable profit margin. That is one major reason why no large energy companies are seriously considering building a new coal-fired power station in Australia;[65] the capital costs are large, and the risks are too high that prices over a multi-decade operating life will not be enough to support the investment.[66]

Consumers today benefit from the sunk capital of legacy coal assets built decades ago, and will continue to benefit from them until those assets are retired, regardless of whether they are replaced with new coal or new renewables. But conflating the price at which existing coal bids into the NEM today with the price needed to support investment in new coal is a mistake. A system that relies on capital investment in more coal will not deliver lower prices over the long-run.

2.2.2 Increasing the renewable share to 70 or even 90 per cent is a cost-effective way to reduce emissions

It might seem surprising that the renewables-based systems are not substantially cheaper than the coal-based system, given that wind and solar are the cheapest sources of bulk electricity today. Two factors add to the cost of relying on renewable electricity.

First, the best locations for wind farms and solar farms are often far from major population centres, requiring long distances of additional transmission to connect supply to demand. Second, firming the

65. Potter (2018); and Macdonald-Smith (2019).
66. The other major reason is 'carbon risk'. This includes, among other things, the risk that governments will introduce policies that penalise emissions production, making emissions-intensive activities uneconomic: Senate Economics References Committee (2017, p. 6). Building a coal-fired power station – which would produce very emissions-intensive energy for several decades – is therefore a risky move.

renewable supply adds significantly to cost (and our analysis found that a combination of firming strategies – including building storage, more transmission between states, and overbuilding the total capacity – is more cost-effective than relying on any one alone).

Nonetheless, the 'keep coal' and '70%RE' scenarios offer electricity at very similar cost. This means that moving to a mostly-renewable system offers a large quantity of very low-cost abatement: 70Mt fewer emissions per year than the coal-based system, at a cost of less than $7 per tonne of emissions saved.[67] This is less than half what the Federal Government pays for emissions reduction via the Climate Solutions Fund.[68]

In the '90%RE' scenario, demand can be met reliably in a system with zero coal and limited gas (see Figure 2.1 on page 15). The cost of doing so would be about $6.7/MWh more compared to the '70%RE' scenario.

The emissions intensity of the NEM would fall even further: from 0.24t/MWh to just 0.05t/MWh. That's still low-cost abatement – less than $40 per tonne of emissions saved.[69] That is more than the Federal Government pays via the Climate Solutions Fund today, but it is substantially cheaper than the price of carbon in other major jurisdictions. In the EU, the carbon price rose above A$67/t in March 2021, while Canada plans to raise its carbon tax to A$181/t by 2030.[70]

The cost difference between the '70%RE' and '90%RE' scenarios arises partly because more investment in firming is required at higher renewable shares. The '90%RE' scenario also involves additional fuel costs from burning more gas, and an allowance for more synchronous condensers for system security.

There are possible developments, not modelled in our scenarios, that could reduce this cost difference. For example, in our model, wind and solar farms are built only in renewable energy zones (REZs) as defined by AEMO.[71] Transmission is built to each REZ so that wind and solar output is not constrained by congestion. It may be more efficient to undersize the connection to each REZ: some power would be spilled at times of maximum production, but the system is likely to have a surplus of energy at those times anyway.

Another possible development could be to co-locate renewables and batteries. In each of the modelled scenarios, batteries are assumed to be near demand centres. If batteries are co-located on wind and solar farms, then at times of grid congestion extra power can be stored for discharging later. There may also be capital cost savings. Batteries and solar both use 'direct current' (DC). But power flow in the grid is 'alternating current' (AC). As such, solar and batteries require DC-AC inverters to switch between the two types of current. By co-locating solar and batteries, these assets can share an inverter.[72]

Our scenarios adopt capital cost projections based on AEMO's 'Central' scenario.[73] AEMO's alternative 'Step change' scenario assumes solar and wind costs that are respectively 15 per cent and 5 per cent lower than the Central scenario by 2040-41, driven by faster global

67. The difference in system unit cost is about $2.5/MWh, while the difference in emissions intensity is about 0.37t/MWh.
68. At the 11th auction in September 2020, the Federal Government contracted 7Mt of abatement at an average cost of $15.74 per tonne: CER (2020a).
69. Comparing the 'keep coal' and '90%RE' scenarios, the difference in system unit cost is about $9.2/MWh and the difference in emissions-intensity is about 0.55t/MWh, yielding an average abatement cost of about $17/t.
70. Bloomberg (2021) and Harvie et al (2020). The average conversion rate over the 12 months to March 2021 is 0.61 AUD per EUR and 0.94 AUD per CAD: RBA (2021).
71. AEMO (2020e).
72. Fu et al (2018).
73. AEMO (2020a).

deployment of renewable technologies.[74] If these more aggressive cost reductions emerge, then the gap between the system unit costs of the scenarios would be reduced.

Other possible developments, including the effect of a large-scale renewable hydrogen industry or greater uptake of electric vehicles, are discussed in Section 3.4 on page 38.

2.2.3 The value of transmission increases at high levels of renewables

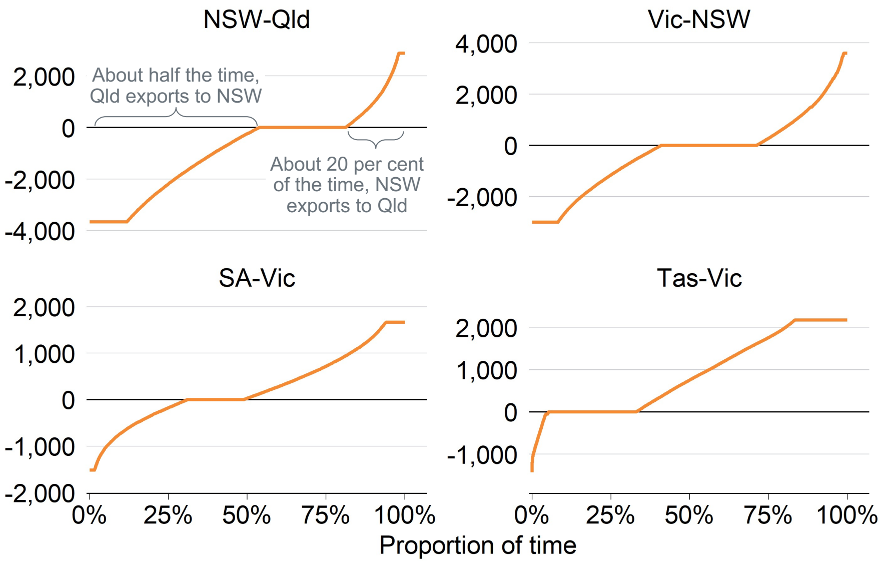
Section 2.1.1 on page 16 demonstrated that the suite of transmission projects considered in this analysis becomes increasingly valuable as the renewable share grows. All states will benefit from the interconnected NEM even more than they do today.

This is despite more and more consumers generating, storing, and using their own power, sourced from rooftop solar and stored in batteries. With so much decentralised generation happening right where power is needed, one might expect that towns, cities, and states will actually be more self-sufficient, weakening the case for large, expensive transmission lines between regions.

The results in this report do not support that conclusion. The scenarios analysed assume a very high level of rooftop solar and behind-the-meter battery storage in the future, using AEMO's 'High DER' (distributed energy resources) projections – 32GW and 18GW respectively across the NEM.[75] And yet, as the share of grid-scale renewables grows, better interconnection between states helps to lower the cost of supplying electricity reliably.

Local generation does not undercut the case for transmission. If it's cloudy over Melbourne for three days, most of Victoria's rooftop solar production will slump. When variable renewable energy output is much less than demand in a region, it makes sense to source power from other regions with surplus energy. Figure 2.6 shows that in a high-renewables future all states will rely on each other at least some of the time.

Figure 2.6: All states import and export power some of the time
Forward power flow (MW) across modelled hours in the '90%RE' scenario (negative values mean flow in the opposite direction)



Notes: The x-axis is the proportion of time that flow is equal to or greater than the value shown (known as 'probability of exceedance'). Flow is measured at the exporting state. The planned SA-NSW Project EnergyConnect link has been modelled as two separate links, one between SA and Victoria, and one between Victoria and NSW.

74. The Step Change scenario assumes global action on climate change consistent with 1.4-to-1.8℃ of warming by 2100; the Central and High DER scenarios assume slower action, leading to 3-to-4.5℃ of warming: AEMO (2019a, p. 21).
75. AEMO (2020a) projects that there will be 35GW of 'embedded' energy storage by 2040, 17GW of which will be aggregated in virtual power plants (VPPs) and 18GW of which will be behind-the-meter. Grattan's modelling does not assume any VPPs: all storage is either behind-the-meter or utility-scale.

3 Net zero is the right goal

The NEM can move from mostly-coal to mostly-renewables without posing major risks to either reliability or affordability of electricity supply. A system with 90 per cent renewable energy would reduce Australia's emissions by 105 million tonnes per year compared to maintaining a coal-based system, at an average cost of less than $20 per tonne.

But at 90 per cent renewables, there would still be an average of 10Mt of emissions per year. The final stretch to zero is harder. The main challenge is 'the winter problem': demand for electricity is higher on average in winter, when solar output is lower.

To meet its climate commitments, Australia has two options for the electricity sector: a **zero emissions** approach (see Box 5), eliminating all sources of emissions; or a **net-zero emissions** approach, where some carbon is emitted but offset with negative-emissions carbon sinks (see Box 7 on page 37).

Which of these options will be the lowest cost in the long term will depend on how fast technologies improve, and the availability and cost of negative-emissions offsets. Based on today's best estimates, governments should commit only to a net-zero future for the NEM, not zero-emissions or 100 per cent renewables.

3.1 The winter problem

Chapter 2 demonstrated that the NEM with 70 per cent renewable energy would be cost-competitive with maintaining the current coal-based system. Increasing the renewables share beyond 70 per cent would mean relying more on 'firming' options other than fossil fuels. At 90 per cent or higher, the cost of these options would begin to materially add to the overall cost of supplying electricity.

Box 5: Distinguishing between net-zero emissions, zero emissions, and 100 per cent renewables

Net-zero emissions is a more flexible target than zero emissions: a net-zero target means the NEM can continue to produce some emissions, but these must be offset by negative emissions elsewhere in the economy.

A zero emissions target is stricter: the NEM cannot be a source of emissions. That means fossil fuels cannot be used unless they are coupled with virtually 100 per cent effective carbon capture and storage (CCS).

A 100 per cent renewables target is stricter still. A 100 per cent renewables system would permit only renewable electricity, including fuels such as hydrogen that are themselves made using only renewable electricity. Neither fossil fuels with CCS nor nuclear energy would qualify.[a] This stricter target would benefit the climate equally as well as a net-zero target, but is less flexible and so harder to achieve.

a. Nuclear energy based on uranium is technically a non-renewable energy source, because uranium deposits are finite.

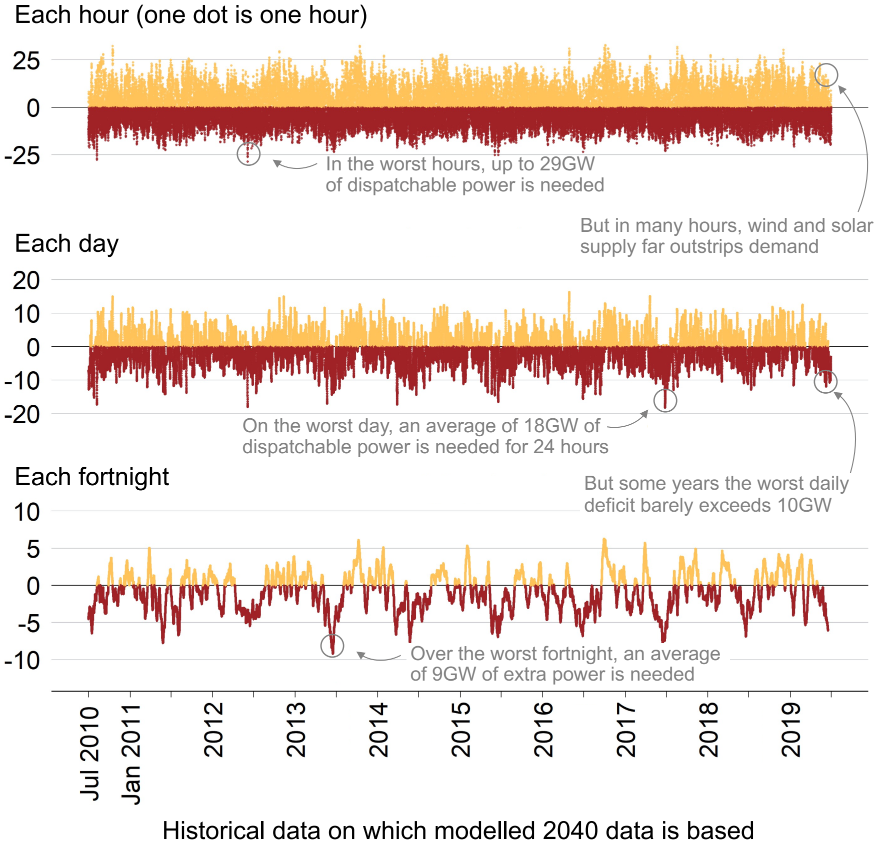
A major reason is that a seasonal challenge emerges as the renewables share grows.[76] This 'winter problem' has to be solved if Australia is to achieve a net-zero electricity system at lowest cost.

Average daily demand in the NEM tends to be higher in winter, partly due to additional demand for heating. Yet solar output tends to be lower in winter, because there are fewer hours of daylight.[77] Wind farms generally perform better in winter, but they are more expensive to deploy than solar.[78] And there are still periods of low wind which must be balanced or 'firmed'. That means the system will tend to rely on dispatchable capacity – such as hydro, storage, or any remaining fossil fuels – more in winter, with a surplus of energy available during the other seasons.

To illustrate the size of this challenge, Figure 3.1 plots the difference between available variable renewable energy and demand on the mainland NEM in the '90%RE' scenario. If more variable renewable energy is available than demand, there is a surplus of energy; if less, there is a deficit, which must be filled with dispatchable capacity. Across the nine years, there could be anywhere from 30GW too much variable renewable energy capacity to 29GW too little in a given hour.[79]

Figure 3.1: Long stretches of low renewables output and high demand make winter a problem

Average wind and solar supply minus demand (GW), across different timescales



Notes: In the '90%RE' scenario, combined wind and solar output is about 0.8GW less than demand on average, with the energy deficit filled by hydro and gas. Storage plays a role in short-term balancing. Days and fortnights are calculated on a rolling basis.

76. This challenge has also been noted by IEA (2019), AEMO (2020e, pp. 51–52) and Leitch (2020).
77. McConnell et al (2021). Rooftop solar output is also lower in winter, which adds to consumer demand on the NEM.
78. AEMO (2020h); and AEMO (2020a).
79. These figures are specifically for the system mix used in the '90%RE' scenario, which had 27GW of utility-scale solar and 37GW of wind. Building more variable renewable energy or locating some in more-remote or better-quality zones could reduce the size of the worst deficit, but add to system cost. In the real world, both 'demand response' (consumers voluntarily reducing their demand on the NEM during peak periods) and 'load shedding' (rolling short-term blackouts to reduce demand) can be cost-effective strategies to reduce the amount of dispatchable capacity needed.

Energy deficits are harder to solve the longer they last; storage or ‘demand response’ can help only for limited durations, such as a few hours to a day or so.

An average of 18GW of dispatchable capacity is needed over the worst 24-hour period modelled in the ‘90%RE’ scenario (Figure 3.1 on the previous page). A particular combination of weather and demand patterns based on the winter of 2013 results in a very challenging fortnight: an average of 9GW of dispatchable capacity is needed. That’s 3TWh of additional energy over the fortnight – the equivalent of nine Snowy 2.0 projects, assuming they start the fortnight full.[80] In other years, less than 2TWh is needed in the worst fortnight. The depth of the challenge varies year to year, but these especially-difficult periods are most common in winter.

Addressing this energy deficit is the key challenge. As discussed in Section 1.2 on page 7, the options include overbuilding renewables,[81] building more transmission, building storage, consumers reducing their demand, or using a dispatchable fuel (such as biomass, gas, or hydrogen). The pros and cons of each strategy are discussed in the next section.

In the ‘90%RE’ scenario, the lowest-cost solution to the winter problem is to primarily use gas as a backstop (see Box 6 on page 30), complemented to a lesser degree by hydro and storage. Figure 3.2 on the following page shows the seasonal reliance on different sources of generation in the mainland NEM states. Gas is used more intensively in winter; storage – in this case, battery storage – is used less, partly because there is a lack of surplus variable renewable energy available to store.

80. Snowy 2.0 will be able to supply up to 2GW for 175 hours, 0.35TWh in total.
81. This would effectively shift the lines in Figure 3.1 up.

3.2 The economics of eliminating emissions in the NEM look challenging

As the share of wind and solar in the NEM grows and displaces fossil fuels, it will be vital to ensure that the renewables supply remains ‘firmed’ – particularly on those rare occasions when swathes of the NEM are cold (pushing up demand), cloudy (reducing solar output), and still (reducing wind output) for consecutive days.

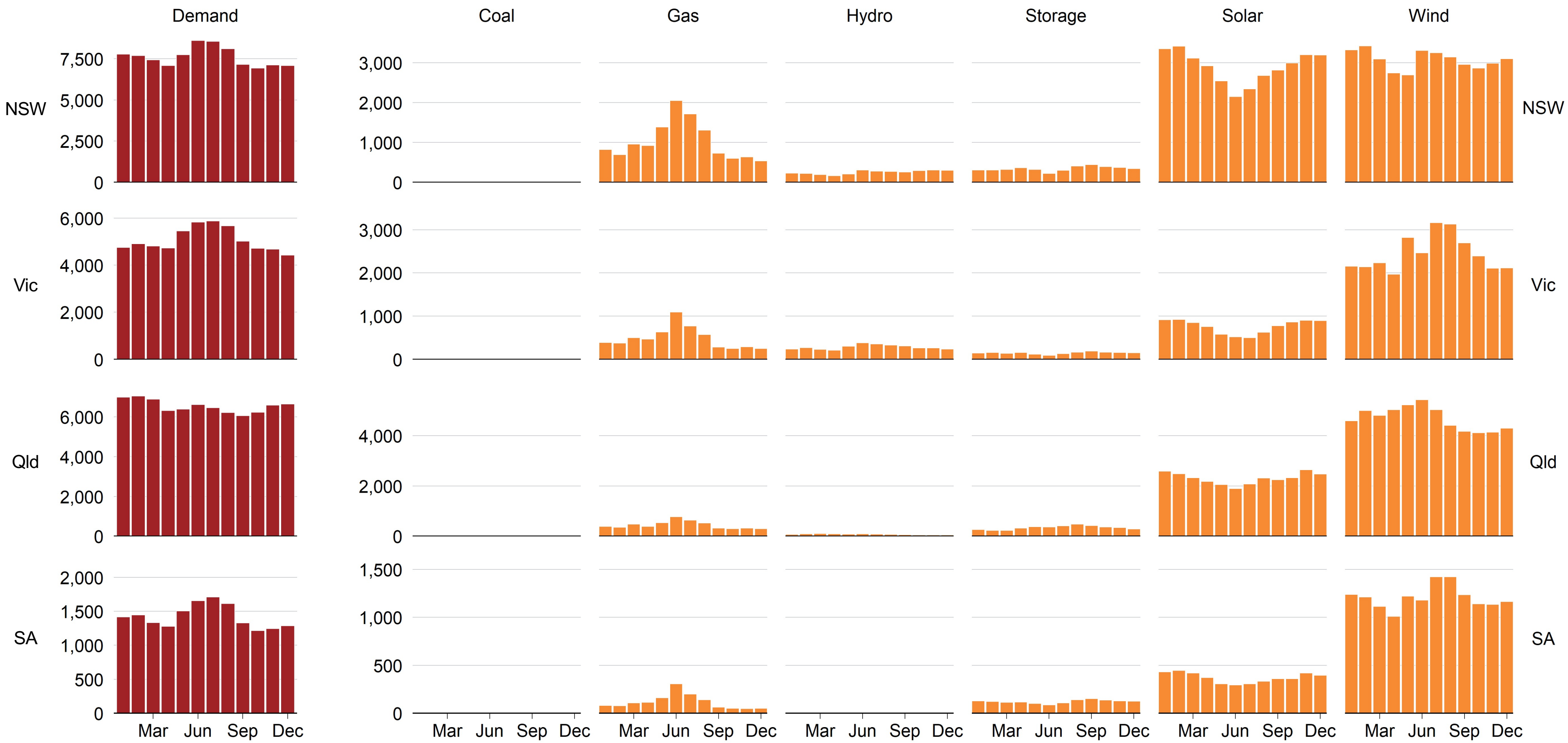
The ‘90%RE’ scenario achieves firming primarily by using gas. But this is not a zero-emissions solution – there would still be an average of 10Mt of emissions produced each year from burning the gas. Closing this gap would require either eradicating the remaining emissions by deploying only zero-emissions solutions, or offsetting the emissions by paying for negative-emissions abatement. Section 3.3 on page 35 analyses the economics of the latter approach.

None of the zero-emissions solutions is a panacea. The options include:

- Overbuilding variable renewable energy capacity even more, and accepting additional ‘spilled’ energy;
- Building more transmission between NEM states and renewable energy zones;
- Building deep storage;
- Making it more attractive for consumers to reduce their demand on the NEM during peak periods; and
- Building zero-emissions dispatchable capacity, such as biomass, hydrogen fuel cells or turbines, nuclear, geothermal energy, or dispatchable fossil fuels with near-perfect carbon capture and storage (CCS).[82]

82. Most examples of CCS today capture about 90 per cent of emissions: IEA (2020) – at that rate, offsets are still needed to get to net zero.

Figure 3.2: Gas helps to balance higher demand and lower solar output in winter
Average monthly electricity demand (MW) and output (MW) in the '90%RE' scenario



Notes: CCGT = combined cycle gas turbines. OCGT = open cycle gas turbines. Tasmania has been excluded because it is assumed to have only hydro and wind generation in all scenarios.

Box 6: Why gas is an ideal backstop in a high-renewables system

The economics of gas-fired generation makes it ideal for providing backstop capacity in a system powered mostly by solar and wind. Gas and liquid fuels (such as diesel) are much better suited than coal to ‘firming’ renewables. This is because they can be burned in turbines or reciprocating engines, which can ramp up and down quickly to balance fluctuations in electricity demand and renewable supply.

Gas and liquid fuels are more expensive than coal per unit of energy,[a] but their plants are cheaper to build: Graham et al (2020a) indicate that a gas peaking plant is 57 per cent cheaper to build than an equivalent capacity of black coal-fired generation, and 72 per cent cheaper than a brown coal plant. And because gas plays only a backstop role rather than supplying bulk energy, relatively little gas is needed – about 95-to-195PJ per year in the ‘90%RE’ scenario, compared to more than 1,000PJ of coal per year in the ‘keep coal’ scenario.

It’s much easier and cheaper to store gas and liquid fuels than hydrogen or electricity. Liquid fuels in particular can be stored at ambient pressure and temperature. This makes them ideal for energy storage in case of a particularly challenging winter. Even if in future renewable energy provides 100 per cent of the NEM’s electricity most years, it may be worth maintaining a reserve of liquid fuel and some fast-start generator capacity in case of a period of unprecedented bad weather. Liquid fuels are even more expensive to burn than gas, but used in this way only very small volumes would actually be consumed.

Australia already has substantial infrastructure for moving and storing gas and liquid fuels, such as pipelines, underground storage, and refineries. Existing gas infrastructure is useful but not essential for enabling gas to play a backstop role. If demand for gas in other sectors declines over the coming decades to meet Australia’s climate goals, parts of the existing gas networks may not be economic to maintain.[b] In that case, LNG regasification terminals may offer an economic alternative for supplying gas to power plants. These terminals receive shipments of LNG, and warm it back from a liquid to a gaseous state as needed. LNG could be imported from elsewhere in Australia, or internationally.

Regasified LNG might be slightly more expensive than gas today, but this option is very flexible. The amount regasified can vary significantly from day to day, and extra LNG can be bought on the global spot market if required.[c] Fortunately for Australia, challenging winters would occur during northern hemisphere summers, when Asian gas demand and prices typically fall. And the terminals can be built as floating units, allowing them to be transported elsewhere if not needed – an option not available with pipelines and underground caverns.

However, gas and liquid fuels are not zero-emissions solutions. To achieve net zero, their use must decline over time or be offset with negative-emissions technologies.

a. The analysis in Section 2.1.3 on page 19 assumes a gas price of between $11.49/GJ and $13.86/GJ depending on location and type of gas-fired generator (Appendix A.1.5 on page 52). The option of using liquid fuels was not tested explicitly; these are expected to cost closer to $30/GJ. Black coal is estimated to cost $3/GJ, and brown coal $0.67/GJ.
b. Wood and Dundas (2020, p. 55).
c. AGL’s proposed ‘floating storage and regasification unit’ for Victoria would have supplied 45PJ of gas per year (12 LNG shipments), with the option to scale up to 160PJ if needed (40 shipments): AGL and APA (2020, Chapter 4, pp. 6-8). This unit could have supplied 550TJ per day reliably, and up to 830TJ per day if supply and maintenance allowed: AEMO (2019b, p. 62). In March 2021 the state’s Minister for Planning Richard Wynne effectively blocked the proposal on environmental grounds: DELWP (2021a).

Given the nature of the challenges facing high-renewables systems – intermittent supply and seasonal energy deficits – the most attractive 'firming' solutions will be cheap to build even if expensive to operate. Low-capex, high-opex solutions are ideal because they will be called on to provide electricity only infrequently – when wind and solar output can't meet demand. That means there are few units of electricity over which to recover capital costs, so capital costs need to be low. And it means few units of electricity incur operating costs, so the per-unit cost of generating electricity can be fairly high without changing the asset's overall economics or inflating average costs of electricity supply very much.

This section compares the feasibility and economics of each of the zero-emissions methods for firming a high-renewables NEM.

3.2.1 Substantially overbuilding variable renewable energy generation

The first option to manage long-duration energy deficits is deploying vastly more wind and solar. In Figure 3.1 on page 27, the 9GW gap between variable renewable energy supply and demand over the worst fortnight could be closed by building tens of gigawatts more wind and solar, especially in places that tend to be windy or sunny when large parts of the NEM are not. That would mean energy deficits would be less severe, requiring less other firming. But it would also mean far more energy is produced at other times, much of which would be wasted. And all of that extra capacity is likely to require more transmission as well, especially if built in far-flung corners of the NEM.

In the '90%RE' scenario, there is already some overbuilding. About 10 per cent of renewable energy is wasted, which happens when supply far exceeds demand and storage systems are not able to absorb all of the excess power. Some wastage is not necessarily a bad thing; given how cheap it is to produce variable renewable energy, allowing some to be 'spilled' is an efficient way to ensure more energy is available when wind and sunlight are scarce.

But building tens of gigawatts of extra renewable energy is likely to be economic only if the capital costs of wind and solar fall much further than assumed in this report, or if a new, flexible source of demand emerges to take advantage of the power that would otherwise be wasted (this possibility is explored more in Section 3.4 on page 38). And even with substantially more renewable generation, other firming options may still be needed to secure genuinely reliable supply.[83]

3.2.2 Building substantially more transmission between NEM states and renewable energy zones

The second option is to significantly increase the transmission capacity between states, and connect to more renewable energy zones. This option can really only succeed if coupled with variable renewable energy overbuilding. That way, by harnessing the geographic diversity of the NEM, the variability of renewable supply should be somewhat smoothed out – it's extremely unlikely to be simultaneously still and dark everywhere across the NEM at once. But to really capture diverse renewable energy sources, ever-more-distant renewable energy zones will need to be connected, which means much more transmission infrastructure at greater cost, with greater losses along the lines.

For example, far north Queensland has some high-value wind resources.[84] But it is also more than 1,500km from Brisbane, the

83. A system with 54GW of wind, 43GW of solar, 11.5GW of pumped hydro, and 42GW of batteries was tested, but even this could not meet about 4.1GWh of consumer demand each year – and the system unit cost was about $150/MWh. Alternative, untested zero-emissions mixes may be able to achieve acceptable reliability at lower cost, especially if some renewable fuels such as biomass or hydrogen are used, but it is unlikely that they could achieve costs as low as the $100/MWh of the '90%RE' scenario by 2040.
84. Wind farms in the far north Queensland renewable energy zone are expected to achieve capacity factors of 50 per cent or more: AEMO (2020a). That means

nearest major capital city. Expanding the transmission network to better connect far north Queensland to the NEM is estimated to cost $910 million per gigawatt of capacity.[85] But to strengthen the entire backbone so that additional capacity can reach Brisbane is estimated to cost an additional $1.4 billion per gigawatt, effectively doubling the delivered cost of the wind power.[86]

The results in Chapter 2 suggest that extra transmission between states can help to reduce system unit cost at high levels of renewable penetration. It's very likely that even stronger interconnection than was tested could prove useful as the renewable share grows beyond 90 per cent. For example, Lu et al (2021) find that building tens of gigawatts of interstate capacity could help to deliver zero-carbon electricity in Australia.[87] This is vastly more capacity than there is today or than was considered in this report's scenarios. It may be possible to deliver at the costs assumed in that paper, but the risk of cost overruns on such nation-building infrastructure is substantial,[88] and AEMO did not find a case for large-scale high-voltage direct current transmission.[89]

a 1GW wind farm would produce more than 500MW of power on average; an impressive result for a renewable energy project.

85. Ibid.
86. Based on the costs of group constraints NQ1, NQ2, and NQ3 in AEMO (ibid). The capital cost to build wind in far north Queensland is estimated at $1.5 million per MW by 2040.
87. Lu et al assume 'high-voltage direct current' (HVDC) transmission technology is used, rather than the 'high-voltage alternating current' (HVAC) more commonly used in the NEM. The only HVDC links in use in Australia today are the Terranora Qld-NSW interconnector, the Murraylink SA-Vic interconnector, and the Basslink Tas-Vic interconnector. HVDC as a technology is better suited to transporting power long distances with relatively low losses.
88. Terrill et al (2020).
89. AEMO did consider HVDC connections linking SA-Qld, Vic-NSW, and NSW-Qld, but they were not included in the list of 'actionable' or 'future' projects because they either did not deliver net benefits to consumers or did not offer additional renewable energy zone connection benefits that HVAC transmission did: AEMO (2020e, Appendix 3, pp. 65-67).

3.2.3 Building very substantial deep storage capacity

The third option is to build more deep storage. Considerable short-to-medium duration storage is likely to be built to deal with daily and more-regular supply-demand imbalances. With enough storage reserves, the seasonal imbalance between solar output and demand could in theory be managed. But as Figure 3.1 on page 27 shows, to supply 9GW of dispatchable power for 14-straight days would require very large storage capacity: at least nine Snowy 2.0 systems, assuming that they all start the fortnight full. There may not be enough high-quality pumped hydro locations in the NEM for this to be feasible.[90] And even if there are, the costs of delivering this amount of storage would add at least 75 per cent to the system unit cost.[91]

That raises a second issue: imperfect foresight. Without knowing in advance when the most challenging days and weeks of the year will be, storage systems may not be adequately stocked when they're needed.[92] And given that the worst fortnight in some years is much worse than in others, some of the storage capacity needed to ride through a once-in-a-decade challenge will sit idle in other winters – a very difficult financing proposition.[93]

90. AEMO (2020a).
91. To supply 9GW for 14 days, 3TWh of energy storage is needed. That would mean 63GW of 48-hour pumped hydro. Using the pumped hydro costs for NSW in AEMO (ibid), the capital and fixed operations and maintenance costs for this much pumped hydro would add more than $100/MWh to the system unit cost, with a saving of about $25/MWh from not requiring gas plants or fuels. Yet even 3TWh of storage is not enough to guarantee reliability, because the storage must start the most challenging fortnight full. Additional wind and solar capacity would also be needed.
92. Hydro Tasmania (2019, p. 10).
93. Consider a system relying mainly on storage for backup with a very small amount of gas capacity with CCS. Storage operators may need to keep some energy in reserve throughout winter to ride through a possible tight fortnight in late August, where the fortnight-long deficit is too big for the gas capacity to supply. That means storage would cede market share to the gas generators throughout

Existing hydro systems share some similarity with storage systems: they offer large amounts of dispatchable capacity, but the total amount of electricity they can generate is ultimately limited by the rate at which water flows into the reservoir.[94] For example, Hydro Tasmania operates a system of lakes and rivers which can dispatch about 2GW and hold about 14TWh of energy in total.[95] But it's unlikely that hydro's role will grow, for two reasons: most of the best sites have already been developed,[96] and the energy available each year is largely determined by rainfall, which is variable, subject to drought, and projected to decrease on average due to climate change.[97]

3.2.4 Making it more attractive for consumers to reduce their demand on the NEM during peak periods

The fourth option involves managing the demand side of the electricity system, rather than the supply. This already happens today: when supply and demand are very tight, some major electricity users such as smelters temporarily decrease their demand on the system and are compensated.[98] And market operators often urge households to conserve energy during peak periods.[99] These are useful ways to manage short-term supply constraints.

But the main challenge facing a high-renewables system is likely to be infrequent yet persistent energy deficits in winter, where the conditions could last for days. Conventional 'demand response' will not be effective here: smelters can turn down for only a few hours, and consumers would find it difficult to avoid energy-intensive activities over consecutive days.

Some demand-side solutions may emerge as the system evolves. For example, if tariff structures are more closely linked to wholesale prices, then factories may choose to schedule maintenance in winter when electricity prices are likely to be higher, rather than over the December-January holiday period as is typical today. Higher winter prices may encourage households and workplaces to reduce their energy use by installing better insulation. But most demand-side measures are unlikely to materially reduce the winter deficit challenge.[100]

3.2.5 Building zero-emissions dispatchable capacity

The fifth option is zero-emissions dispatchable power. As noted above, more traditional hydro is unlikely to be built at sufficient scale. But there are other renewable or zero-emission fuels, including biomass, fossil fuels with carbon capture and storage, nuclear, hydrogen-fired power plants, or other more niche renewable technologies. Today, the economics of each technology looks to be challenging for solving the winter problem.

Biomass is made from plants, which absorb carbon dioxide as they grow and release it when burned, making the fuel carbon-neutral.[101] But low-cost biomass is relatively scarce in Australia[102] – while some agricultural or forestry waste is available cheaply, increasing biomass

winter for the sake of system reliability. If that difficult fortnight never eventuates or the deficit is smaller than expected, the storage operators will have foregone substantial revenue, and consumers will have paid more for expensive gas energy than was really necessary. This will be apparent only in hindsight.

94. This applies only to hydroelectric dams. 'Run-of-river' systems generate power in a non-scheduled manner, with output dependent on natural stream flow.
95. Grattan analysis of Hydro Tasmania (2021).
96. Geoscience Australia (2019).
97. AEMO (2020a).
98. DISER (2020b).
99. AEMO (2020i); and Irfan (2021).
100. The possible exception is an export-scale renewable hydrogen industry if demand for hydrogen is lower in winter than at other times of the year; this possibility is discussed further in Section 3.4.3 on page 40.
101. Provided that the land is managed sustainably and that existing carbon sinks are not disrupted to make room for biomass plantations.
102. Wood et al (2020, p. 17).

production would require dedicated farming. Biomass could also be in demand in other sectors, such as manufacturing.[103] For example, it is a possible input to sustainable aviation fuels or bioplastics, and could be a source of renewable industrial heat. This extra demand coupled with its limited supply would push up its price.

Biomass-fired power stations are even more capital-intensive than coal-fired ones.[104] Their fuel costs are estimated to be similar to those of coal.[105]

As explained earlier, this means they are inherently less well-suited to balancing a renewables-based grid: wind and solar would be abundant for much of the year, so biomass power plants wouldn't have much of an opportunity to recover their high capital costs.

Coal and gas generators fitted with carbon capture and storage have very similar challenges: they are capital-intensive and require suitable geology for storing emissions permanently. Graham et al (2020a, p. 37) estimate that deploying carbon capture and storage with a coal plant would nearly double the capital cost, while on a gas plant it would nearly treble it.

That makes them expensive for consumers, and highly risky for investors. While peaking gas plants such as open cycle gas turbines (OCGT) have successful business cases today that rely on being needed only infrequently, they are built without carbon capture and storage and so have much lower capital costs.

103. Ibid (p. 33).
104. Graham et al (2020a, p. 37) estimate the cost at more than $12,000/kW, though more recent estimates suggests it could be closer to $8,000/kW: Graham et al (2020b, p. 67).
105. Graham et al (ibid, p. 70) assume biomass costs about $0.5-$2/GJ, compared to about $3-$4/GJ for black coal, but the efficiency of a biomass plant is about half that of a black coal generator.

In Australia, nuclear energy generation is prohibited by legislation. But even if it were not, it would have similar problems due to its high capital cost. It more closely resembles coal than peaking gas in its ability to ramp up and down to flexibly balance renewable energy.[106] Small-scale modular reactors have received some attention in recent years; Australia should track their development if they can operate more flexibly and if their costs decline significantly.

Hydrogen produces only water as a byproduct when used as the fuel for a gas turbine. It could play a significant role in the future – depending on its cost. Traditional gas turbines can be adapted to run on hydrogen.[107] Alternatively, electricity can be extracted from hydrogen using fuel cells.[108]

The main problem in using hydrogen to solve the winter challenge is the cost of making and storing enough of the fuel in a zero-emissions way. The Federal Government has set a 'stretch goal' of delivering low-emissions hydrogen for less than A$2/kg,[109] which would equate to an energy cost of more than $16 per gigajoule (GJ).[110] For comparison, natural gas today typically costs between $8 and $10/GJ for industrial customers on the east coast of Australia, and is projected to cost between $11 and $14/GJ for gas-powered generation by 2040;[111] coal costs less than $4/GJ.[112] So even if the stretch goal is met, this would be a more expensive source of energy. The National Hydrogen Roadmap estimates that in the absence of a carbon price, hydrogen

106. Morris (2018, pp. 29–31, 47–48).
107. The cost to convert a gas plant depends largely on how much hydrogen displaces natural gas; to get to zero emissions, the plant would need to run on 100 per cent hydrogen, which may require substantial upgrades to be feasible: Goldmeer (2019, pp. 12, 15).
108. CSIRO (2018, p. 35).
109. DISER (2020c, p. 6).
110. Hydrogen Strategy Group (2018, p. 39).
111. ACCC (2021, p. 64); and AEMO (2020a).
112. AEMO (2020a).

would need to cost $1.6/kg to be competitive with natural gas for providing seasonal energy storage.[113]

Hydrogen could in future be competitive with other firming options, but the timing is uncertain. Some analysts see potential for hydrogen to cost $2.1/kg by 2030 and $1.2/kg by 2050, if governments around the world introduce policies to stimulate demand and provide more than $200 billion in subsidies over the next decade.[114]

Assuming the Federal Government's stretch goal of $2/kg is met by 2040, the 18TWh of electricity provided by gas on average each year in the '90%RE' scenario could be provided instead by hydrogen at a cost of about $2.6 billion.[115] That means the fuel costs alone would be about $0.6 billion more per year than if using gas. And hydrogen plants, being a less-developed technology, may cost more to build and operate than gas plants.[116]

Alternatively, hydrogen could be run through a fuel cell to produce electricity. This could be more efficient than burning it,[117] but fuel cells are much more expensive than gas-fired generators: Graham et al (2020a, p. 37) estimate that they cost twice as much as an equivalent capacity of peaking gas plants today, and will still cost two-thirds more by 2040, while having shorter lifespans than gas plants.[118] This means at least $1 billion more per year must be spent on hydrogen fuel cells than would be spent on gas plants. Eliminating 10Mt of emissions for upwards of $1 billion per year is a cost of at least $100/t.

The role of hydrogen is explored further in Section 3.4.3 on page 40.

Renewable electricity technologies such as geothermal, tidal, or wave power have either a poor development record or are too small or localised to make a material contribution. And 'concentrating solar thermal' technologies would have lower output in winter just as solar photovoltaic technology does, while being several times more expensive to deploy.[119]

3.3 The price of offsets will determine how much energy – if any – should come from fossil fuels in a net-zero NEM

Today's best projections of technology costs in 2040 favour using gas or liquid fuels as a backstop (see Box 6 on page 30) to solve the emerging winter problem. To reach net zero, either the emissions from these fossil fuels must be offset, or zero-emissions alternatives will need to displace fossil fuels. That raises the question: what is the lowest-cost way to reach net zero?

The answer will depend on how quickly zero-emissions firming options improve, and how the costs of fossil fuels and negative-emissions offsets evolve.

For example, at an offset price of $50/t, offsetting the remaining 10Mt of average yearly emissions in the '90%RE' scenario would cost, on average, $500 million per year – a premium of less than $3/MWh of consumer demand. That is a low-cost way to reach net zero, compared with the zero-emissions options canvassed in Section 3.2 on page 28.

113. CSIRO (2018, p. 36). This includes the cost of storing large quantities of hydrogen, probably in salt caverns.
114. BNEF (2020, p. 5), assuming a conversion rate of 0.7 AUD per USD.
115. This assumes that hydrogen is burned in turbines, that there is the same capacity of combined-cycle and open-cycle turbines as in '90%RE' scenario, and that hydrogen achieves the same heat rate as gas.
116. For example, hydrogen peaking plants based on reciprocating engines are projected to still be 19 per cent more expensive than gas reciprocating engines by 2040, a premium of $293/kW: Graham et al (2020a, p. 37).
117. Estimates for the heat rate of hydrogen fuel cells range from 7.7GJ/MWh by CSIRO (2018, p. 89), to 9.6GJ/MWh by Aurecon (2019, p. 40), to 11.3GJ/MWh by AEMO (2020j) and Aurecon (2020a, p. 52). For comparison, the heat rate for gas is 7.6GJ/MWh when burned in a CCGT or 11.7GJ/MWh in an OCGT: AEMO (2020a).
118. Aurecon (2019, p. 41).
119. Graham et al (2020a, p. 37).

It is possible that wind, solar, or storage costs could fall even more dramatically than expected.[120] New technologies could emerge. Retailers and governments could find creative ways to encourage consumers to manage their consumption more cleverly, shifting demand patterns.

In the absence of these developments, it is the cost of using fossil fuels with offsets that will dictate the cheapest way to deliver net-zero electricity in the NEM. There are two components of this cost: the cost of the fuel, and the cost of the offsets. Buying $20/t offsets would add about $1/GJ to cost of using gas; $200/t offsets would add $10/GJ, potentially doubling the cost of gas.[121] The price of offsets will depend on the supply of offsets, and the demand from other domestic sectors and possibly from international markets.[122]

At 'net zero', the only offsets that can be used are methods for capturing carbon dioxide from the atmosphere and storing it permanently (Box 7 on the next page).

That means the supply of offsets will be practically and economically constrained by the technologies for removing emissions. Nature-based solutions, such as trapping carbon in trees or soil, have physical limits: land is scarce, and soils can hold only a limited amount of carbon. There are costs associated with implementing, maintaining, and verifying emissions removal.

120. AEMO expects utility-scale solar to fall 49 per cent to $654/kW by 2040-41 in its 'Central' scenario, but fall 57 per cent to $554/kW in its 'Step change' scenario: AEMO (2020a). That would reduce the system unit cost of the '90%RE' scenario by about $1.3/MWh, with an even greater impact on the cost of a zero-emissions system.

121. Based on an emissions factor of 51.5kg of CO_2-e per GJ of gas burned: DISER (2020d, p. 12).

122. This will depend on whether Australia is willing to use international offset credits to meet domestic emissions targets or if Australian credits are exported in significant volumes.

And as the demand for offsets in other sectors grows, so will the cost. In a net-zero world, 'hard to abate' sectors in particular will compete for offsets: these include LNG, aviation, shipping, cement, steel, and plastics. Progress, or a lack thereof, in decarbonising these industries will affect the price of offsets for the electricity sector, thereby influencing the most economic ratio of renewable-to-fossil energy in the NEM.

Figure 3.3 on page 38 illustrates this situation. If offsets are abundant in future and as cheap as they are today – which is extremely unlikely, given that avoidance credits cannot be used to reach net zero – then there could be a substantial role for fossil fuels without carbon capture and storage over the long term. For example, at an offset price of $20 per tonne of emissions, it would be cheaper to deliver net-zero electricity using the generation mix from the '70%RE' scenario than the '90%RE' scenario. That means fossil fuels could continue to supply about a quarter of the energy in the NEM.

But the cost of offsets is likely to rise substantially. Energy consultancy Reputex forecasts that the offset price is likely to rise to anywhere between $30 and $100/t by 2040.[123] At net zero, the price will probably be much higher, given that only negative-emissions credits can be used to offset NEM emissions. And as offset prices rise, the amount of emissions-intensive generation in a net-zero NEM will fall, and zero-emissions alternatives will become more cost-competitive.

If other jurisdictions offer any guide, the offset price could rise quickly. Canada's carbon price is set to rise CAD$15 per year from 2023, reaching CAD$170/t by 2030 (A$181/t)[124] – with that policy, any offsets available for less than CAD$170/t represent good value, and would be expected to be purchased. If offset credits can be traded internationally, other nations' demand for offsets could push up the price in Australia.

123. Macdonald-Smith (2021).

124. Harvie et al (2020).

Box 7: To achieve net zero across the economy, only certain types of offsets can be used

The Climate Solutions Fund is a Federal Government program that pays people or businesses to reduce or remove greenhouse gas emissions. Activities that reduce or remove emissions can earn one Australian carbon credit unit (ACCU) per tonne of CO_2-e. These credits can be sold to the Federal Government or to businesses, to offset their emissions.

There are several methods of generating carbon credits, but they fall into two main categories: 'avoided' emissions and 'negative' emissions.

Avoided emissions methodologies involve making an activity less emissions-intensive. Some examples are improving the energy efficiency of a building, switching to lower-emissions aviation fuel, burning waste methane from coal mines, changing agricultural feedstocks so cattle belch less methane, or avoiding deforestation despite having a permit to clear the land.[a]

Negative emissions methodologies involve removing emissions from the atmosphere and sequestering them permanently in trees or soil.[b] In future, capturing emissions directly from the air or from bioenergy projects and storing them permanently underground should also be acceptable methodologies.[c] Australia has many onshore and offshore basins that could be suitable for large-scale, permanent carbon dioxide storage, especially in WA, southern Victoria, and west of the Great Dividing Range.[d]

In a net-zero economy, only negative emissions methodologies can generate credits for offsetting emissions.[e] That's because net zero, by definition, means that all emission sources must be exactly countered by emissions sinks. Consider an economy with just two businesses, neither of which produce emissions. If one business wants to produce emissions, then to stay at net zero it must pay the other business to offset its emissions by removing carbon from the atmosphere. New emissions cannot be offset by paying the second business to avoid emitting, because the second business has no emissions to avoid.

Cost estimates for many negative-emissions technologies vary widely, and there is additional uncertainty in determining exactly how many emissions some processes can effectively remove. In general, reducing emissions at the source is usually more economic than removing emissions from the atmosphere.[f] Negative-emissions technologies are therefore not a substitute for reducing emissions, but rather a complementary strategy, helping to offset only those emissions that would be uneconomic to attempt to eliminate.

a. CER (2021a).
b. Permanent in a dynamic sense: though individual trees will die and release carbon, new ones will grow and capture it again. If the overall stock of trees is increased then the net amount of carbon in the biosphere will rise, and the net amount in the atmosphere will fall. Effectively, carbon will be stored for as long as the stock is not diminished (by land clearing, for instance).
c. These processes are known as 'direct air carbon capture and storage' (DACCS) and 'bioenergy with carbon sequestration and storage' (BECSS) respectively. Other negative-emissions processes – such as using CO_2 to produce useful materials (mineral carbonation) or chemically reacting dissolved carbon dioxide in rainwater with crushed rock (enhanced weathering) – are likely to provide only modest mitigation opportunities: Cook and Arranz (2020, pp. 29–31).
d. Ibid (p. 18).
e. SBTi (2020, p. 31). Sequestration of emissions must also be strictly permanent.
f. Cook and Arranz (2020, pp. 13, 23–31).

As noted in Section 2.2.2 on page 23, progressing from the ‘70%RE’ scenario to the ‘90%RE’ scenario offers abatement at a cost of less than $40/t. If offsets cost more than this, then the generation mix in the latter scenario is a cheaper way to deliver net-zero electricity, requiring the purchase of fewer offsets. This is evident in Figure 3.3 – at most of the offset prices depicted, the system with the highest renewable share offers the cheapest net-zero electricity.

At very high offset prices, e.g. exceeding $200/t, it may be more efficient to completely eliminate emissions in the NEM than to offset them.[125] This can be done by deploying the zero-emissions methods described earlier in this chapter.

3.4 Emerging trends in other sectors will influence the most-efficient outcome for the NEM

Australia’s goal is to move the entire economy, not just the NEM, to net-zero emissions. That will have consequences for both the demand and supply of electricity in the future.

Emerging trends in other parts of the economy may affect the speed of the NEM’s transition to low emissions, as well as influencing the most efficient long-term capacity mix. But they are unlikely to fundamentally change the conclusions drawn from the scenarios analysed in this report. This section looks at the uptake of electric vehicles, gas-to-electric switching in industry and households, the proliferation of rooftop solar, the possibility of large-scale hydrogen manufacturing, and the likely consequences of a warmer, drier climate.

Figure 3.3: The price of offsets will determine the cheapest way to achieve net zero in the NEM

System unit cost ($/MWh), including the cost to offset any emissions

Note: This chart assumes sufficient credits are available at each price to fully offset the average annual emissions of each scenario, which are 115, 45, and 10Mt respectively.

125. Concerns that offsetting should not be the long-term solution to lower emissions and that depending on offsets could rapidly become very expensive are behind the moves by some international jurisdictions to put limits on the role of offsets: IETA (2014).

3.4.1 Demand for electricity will be influenced by trends in other sectors such as transport

As the emissions-intensity of the NEM falls, there will be abatement opportunities in other sectors to switch from fossil fuel use to electricity. The two most obvious examples are the electrification of road transport and the switch from gas to electricity in homes and industry.

The impact of such developments on system unit cost and seasonal challenges will depend on the daily and yearly demand patterns.

The modelled scenarios in this report include partial electrification of vehicles, with 6.6 million electric vehicles contributing about 23TWh (12 per cent) of annual demand.[126]

Electric vehicles could pose a daily challenge for the NEM: uncoordinated, widespread charging could exacerbate peak demand in the evening. This problem could be managed by encouraging drivers to charge their vehicles when electricity is abundant, such as during the middle of the day, or allowing electricity suppliers to coordinate the charging of electric vehicles.

With the right incentives and technology, the fleet of electric vehicles could also provide the NEM with a large source of energy storage. A fleet of 6.6 million vehicles could store about 400GWh of electricity – about as much as Snowy 2.0 – which could be discharged to homes when supply in the NEM is tight. This could reduce the amount of short-term firming required, but is unlikely to solve the problem of a still and cloudy week in winter – consumers will not want to go without driving for several consecutive days.

Australians' driving patterns are very consistent across seasons: the total number of kilometres travelled by road vehicles varies by less than half a per cent each quarter.[127] That means that although an increase in the number of electric vehicles on the road will increase total annual demand in the NEM, it will not influence the seasonal shape of demand or the system unit cost.[128]

In industry, gas is often used for process heating.[129] Industrial gas demand is much flatter than residential or commercial gas demand. Switching to electricity for a daytime process better matches solar availability, possibly reducing the system cost per MWh. Yet for a 24/7 industrial process, there is likely to be minimal impact.

In homes and buildings, gas use is more weather-dependent. About 60 per cent of gas use in Australian homes is for space heating – overwhelmingly in Victoria – and 33 per cent for water heating.[130] While more gas is needed for water heating on cold days, space heating demand varies the most with ambient temperature: on many days no space heating is required at all, and on other days substantial heating is needed. Space heating has strong daily and seasonal patterns.

Electrification of household and commercial gas load would increase electricity demand more in winter than at other times of the year, exacerbating the winter challenge for the NEM. But this effect can be partly mitigated by energy efficiency initiatives such as insulating buildings better. Gas-to-electric switching is unlikely to fundamentally change the conclusions of this report; it is mainly a challenge for

126. AEMO (2020a, p. 23). These figures are for the 'High DER' (Distributed Energy Resources) traces used in the analysis in Chapter 2. In AEMO's 'Central' scenario, only 5.2 million electric vehicles are projected by 2040, consuming 18TWh of energy per year. Today, there are 17.4 million motor vehicles across the mainland states of the NEM: ABS (2020).

127. Grattan analysis of data from 1965 to 2010: BITRE (2011).

128. The system unit cost is the annual system cost divided by annual demand; if both increase by a similar factor, the effect is cancelled out.

129. Outside of LNG production, industrial gas use is mostly for heating or as a chemical feedstock: ARENA (2019, p. 238). Switching to electricity is possible where gas is used for lower-temperature heating, up to about 160℃ today and 200℃ by 2030: ARENA (ibid, p. 45).

130. Wood and Dundas (2020, p. 43).

Victoria, which could receive additional support from Tasmanian wind farms in winter.[131]

3.4.2 Rooftop solar and batteries won't help solve the winter problem

Rooftop solar has grown remarkably in Australia over the past five years.[132] About 3GW was installed in 2020, and a further 3GW is expected on average for each of the subsequent four years.[133]

To reflect this strong growth, the scenarios modelled in this report use AEMO's demand projections that include a high rate of adoption of rooftop solar and behind-the-meter batteries (see Appendix A.1.3 on page 50 for more details).

Faster rooftop solar uptake is likely to push up system unit cost.[134] This is because rooftop solar reduces wholesale demand during the middle of the day, which is when cheap utility solar could be used instead. This leaves a more challenging demand profile for the NEM to satisfy.

Behind-the-meter battery uptake should reduce the daily peak demand challenges facing the NEM, but have little effect on the seasonal challenge. Behind-the-meter batteries can store surplus rooftop solar during the day and discharge in the evening peak, reducing pressure on the NEM especially on hot summer nights. But over winter, rooftop solar output falls just as utility solar output does. That means less energy available for the batteries, and more demand for the wholesale market to satisfy.

131. Provided there is sufficient interconnector capacity. Tasmania's renewable energy zones have excellent wind resources that can often achieve average capacity factors of 50 per cent or higher in winter: AEMO (2020h).
132. CER (2020b, p. 29).
133. CER (2021b, p. 28).
134. The overall cost of electricity for households with rooftop solar may be lower though. The analysis in this report focuses on the cost of NEM-delivered electricity; behind-the-meter infrastructure and the demand it supplies are netted off the system unit cost calculation.

3.4.3 A large-scale domestic hydrogen industry could provide some benefit

A large-scale manufacturing sector based on hydrogen produced with renewable electricity could provide substantial flexible demand for electricity. In theory, this sector could take advantage of electricity supply when it is abundant – such as on sunny days – and turn down or even switch off when renewable energy is scarce. This would help to firm the NEM and address the winter challenge.

However, to produce hydrogen at the scale needed for large-scale, low-emissions manufacturing or export, it is likely that dedicated renewable energy infrastructure will be needed, rather than relying on the NEM. For example, if Australia were to use hydrogen domestically to produce low-emissions steel on the east coast and capture about 6.5 per cent of the global steel market, about 135GW of new variable renewable energy capacity would be needed.[135]

This stand-alone industry is likely to require dedicated transmission[136] from vast wind and solar farms west of the Great Dividing Range to electrolysers on the coast, rather than augmenting the NEM's existing transmission network to accommodate the extra capacity. Nonetheless, there will still be opportunities for the two systems to complement each other. A multi-gigawatt connection between the hydrogen industry and the NEM would allow surplus electricity to be sold into the NEM. However, surplus power may often be available only when the NEM itself is awash in solar during the day.

More interesting is the possibility that renewable energy generators divert some power from the electrolysers to sell into the NEM when the

135. Wood et al (2020, p. 30).
136. Potentially 'high-voltage direct current' (HVDC) transmission.

wholesale price is high. Even on relatively still nights, a 50GW system of wind turbines spanning central NSW and Queensland is likely to produce at least a few gigawatts of power. The ability to offer several gigawatts of capacity to the NEM when the supply-demand balance is tight could offer an economic firming opportunity, helping to lower the cost of both systems.

There may be limits to how much assistance a stand-alone hydrogen industry could provide to the NEM. The most significant problem is that the hydrogen industry may face similar winter constraints due to lower solar output.[137] If industrial users of hydrogen need a steady supply throughout the year, they will be relying on storage more during the darker months to keep their plants running smoothly, reducing both the hydrogen and electricity available to the NEM (see Figure 3.4). But if industrial demand for hydrogen falls during winter – for example, due to low demand from northern hemisphere export markets – then the NEM may benefit year-round.

3.4.4 A changing climate could exacerbate today's challenges but not necessarily future ones

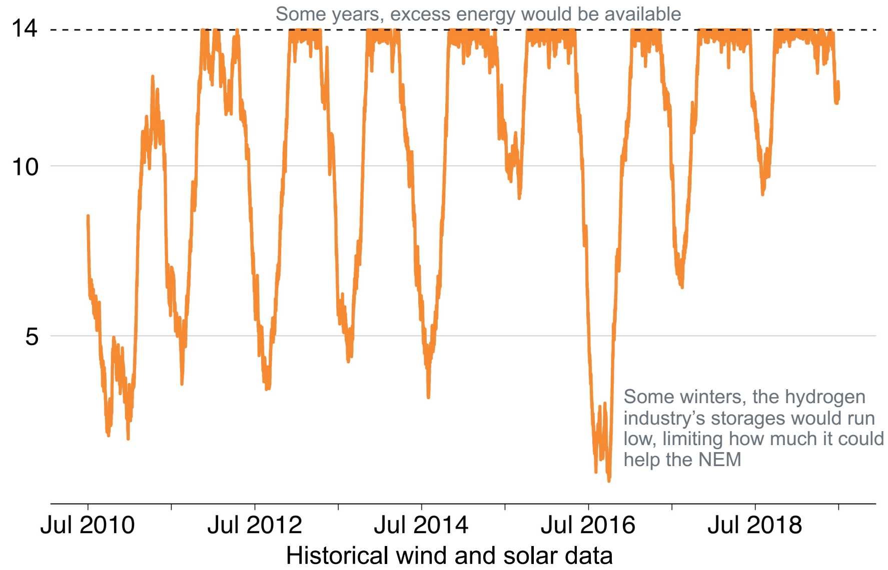
Australia is already 1.4°C warmer than it was at the start of the 20th century.[138] Extremely hot days are becoming more frequent, and extremely cold days are becoming rarer.[139] Across south-east Australia, rainfall in the usually-wetter months of April to October has declined 12 per cent since the late 1990s.[140]

Changing weather patterns associated with a changing climate do not substantially change the conclusions about the long-run future of the NEM with high levels of solar and wind. A warmer climate

137. This problem is worse for southern states than it is for Queensland.
138. BOM and CSIRO (2020, p. 2).
139. BOM and CSIRO (ibid, p. 4).
140. Ibid (p. 6).

Figure 3.4: A large-scale hydrogen industry based on Australia's east coast may itself face a winter energy challenge

Storage level (days remaining) across different weather patterns for a system with 14 days of storage capacity and constant hydrogen demand



Notes: Assumes no electricity or hydrogen is sent to the NEM. Based on a system with 31GW of wind, 46GW of solar, and 42GW of electrolyser capacity in Queensland's Barcaldine renewable energy zone (REZ), and 17GW of wind, 41GW of solar, and 35GW of electrolyser capacity in the NSW Central West Orana REZ. A shared hydrogen storage system is modelled with 14 days worth of hydrogen storage capacity (260,000 tonnes). Electrolyser efficiency is assumed to be 49kWh per kilogram of hydrogen production. The storage system is assumed to start 60 per cent full. Different ratios of wind, solar, electrolysers, and storage may be optimal depending on the future cost of each of these technologies.

means less heating load in winter, somewhat tempering the emerging seasonal problem. The increasing frequency of heatwaves will probably exacerbate the capacity constraints on hot summer afternoons,[141] but these short-lived capacity problems should be easier to solve than seasonal energy problems through demand response and battery storage. And these effects are partially captured in the modelled scenarios: AEMO adjusts its demand traces for future years by estimating the effect of rising temperatures on consumer demand.[142]

Drier conditions were assumed in the modelling of each of our three scenarios, with the energy available in hydro systems reduced by 6.1 per cent to 10.6 per cent depending on the state.[143] If future conditions are drier than this, each of the scenarios would be less able to rely on hydro – but this is unlikely to change the conclusion that pursuing a high-renewables NEM is an affordable way to reduce emissions.

141. Heatwaves and other extreme weather also threaten the physical infrastructure of the system, creating risk of technical failure.
142. AEMO (2020e, Appendix 8, p. 18). In AEMO's 'Central' and 'High DER' scenarios, global warming is assumed to increase over time, reaching 3-to-4.5℃ on average by 2100.
143. AEMO (2020a).

4 The policy path to reliable, affordable, low-emissions electricity

Australia's National Electricity Market (NEM) is being transformed, as new renewable energy sources enter the market and old coal-fired power stations are retired. The challenge for governments and the industry is to ensure the move to a low-emissions future happens at lowest cost and while maintaining reliability of supply. The analysis detailed in this report leads to four major conclusions:

- New generators will come with higher costs than the old coal-fired power stations they replace, regardless of the technologies adopted.
- A system dominated by solar and wind power can be just as reliable and affordable as the present system dominated by coal, but it will need to be balanced with additional transmission and storage, backed up with gas.
- The best information today indicates that the technical and economic challenges will mount if the share of solar and wind climbs beyond 90 per cent, and therefore a target of net-zero emissions for the electricity sector is more economically sound than committing to absolute-zero emissions or 100 per cent renewable electricity.
- The value to all member states and territories of an interconnected NEM will only increase as widely distributed solar and wind generation become the norm.

This report also shows that achieving the twin objectives of low-emissions and reliable supply will be harder, and probably more expensive, with uncoordinated policies. Collective governments asked the Energy Security Board (ESB) to develop recommendations for NEM design to ensure the market remains fit for purpose. Yet, governments recently have been directly intervening in the market. Unfortunately, there is little likelihood of a credible, national emissions policy emerging soon. Therefore the best decision would be for the various governments to prioritise and implement the ESB recommendations on reliability in the context of continuing state-based renewable energy programs.

A single, economy-wide emissions price would be the most efficient way to ensure that emissions in each sector are reduced in an economically efficient manner.[144] But if that remains out of reach, then the alternative is to continue with sector-specific emissions-reduction policies. Australian Carbon Credit Units should be created and traded between sectors, to reduce the cost of this second-best approach.

4.1 Support a high-renewable, no-coal transition

Over the next three decades, virtually all coal-fired power plants are due to close in Australia. This report shows that governments have little to fear from these closures in terms of system reliability and cost.[145] Moving to about 70 per cent renewable electricity is both feasible and affordable – it will not materially change the long-run cost of the system, but will dramatically cut emissions. This is an extremely low-cost abatement opportunity. Even moving to a 90 per cent renewable system would deliver electricity at only slightly higher cost. It would still offer an efficient way to reduce the emissions-intensity of the NEM to less than 10 per cent of what it is today.

144. Wood et al (2016, p. 10). An emissions price would need to be complemented by support for low-emissions technologies development and regulation in sectors with barriers to adoption, such as transport and buildings.
145. Provided that AEMO is able to resolve technical issues related to system security.

Trying to extend the life of existing coal plants – or subsidising the entry of new emissions-intensive coal plants – would only make it harder for Australia to achieve its long-term climate goals. And the high capital cost and limited flexibility of new 'high efficiency, low emissions' (HELE) coal plants with carbon capture and storage makes them ill-suited to balancing or firming a high-renewables system. Subsidising the deployment of such technology would be a poor use of government resources.

4.2 For now, target 'net zero', rather than absolute zero or 100 per cent renewables

All state and territory governments have targets to achieve net-zero emissions by 2050 or earlier. In addition, many governments have policies to achieve a specified share of renewables in their jurisdictions.[146] And some political leaders are discussing the possibility of zero-emissions electricity, or renewable shares of 100 per cent or higher.[147]

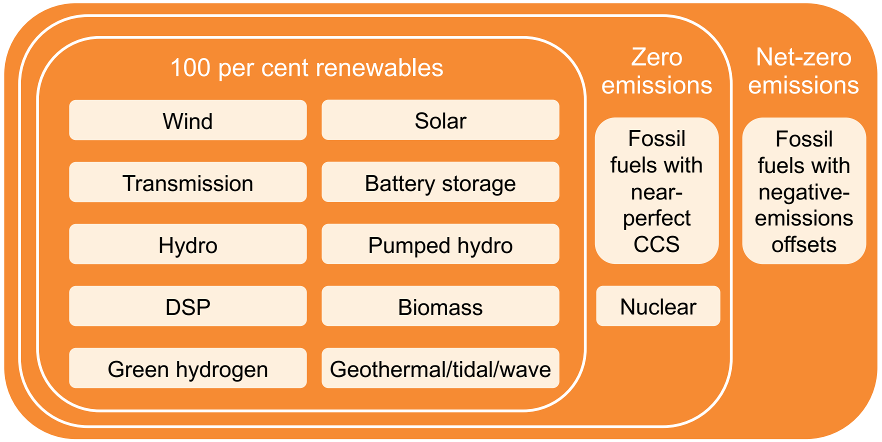
The differences between 'net 100 per cent renewable energy', and '100 per cent renewables' or 'zero emissions' are subtle but important. For example, the South Australian Government aims to achieve 'net 100 per cent renewable energy' by 2030.[148] The use of 'net' here means SA will occasionally rely on non-renewable power, but for each unit of non-renewable energy it uses, it will offset that at other times by exporting renewable power to other states.

146. For example, the Victorian and Queensland Governments each have a target of 50 per cent renewable energy by 2030; the NSW Government promises to deliver transmission infrastructure to facilitate the entry of 12GW of new renewable energy capacity by 2030: DELWP (2021b), DEPW (2021) and NSW Government (2020, p. 26).

147. For example, the ACT Government targeted net 100 per cent renewable energy by 2020: ACT Government (2021). The Tasmanian Government has a target for 200 per cent renewable energy by 2040, which means aiming to produce twice as much renewable energy in 2040 as there is demand today: Barnett (2020). And before the 2021 state election, the WA Liberal Party proposed achieving zero-emissions electricity by 2030, including phasing out all state-owned coal-fired power generation by 2025: Liberal Party of WA (2021, p. 2).

148. Mazengarb (2020).

Figure 4.1: Technologies allowed under each target



Note: DSP = 'demand-side participation'; CCS = 'carbon capture and storage'.

While it's possible for individual states to achieve '*net* 100 per cent' renewable energy, it's not possible for the NEM as a whole to use that convenient approach. The NEM is the entire system – there is no other system to takes its exports. For the NEM, the options are only '100 per cent renewables' – which also implies 'zero emissions' – or 'less than 100 per cent renewables'.

That means that if all states commit to 100 per cent renewable energy targets, the NEM will have a de facto 100 per cent renewable energy target. This limits the technologies available to the NEM (see Figure 4.1). Section 3.3 on page 35 outlined why this could well be a more costly way to reduce emissions than allowing the use of negative-emissions offsets.

Allowing the use of negative-emissions offsets to help the NEM close in on net zero means that there may be a role for gas and liquid fuels in the NEM into the 2040s and beyond. But this role is only to provide backstop capacity for unusually challenging weather and demand patterns. This hardly amounts to a 'gas-led recovery'; it is rather a 'gas-supported transition'.[149] As other zero-emissions alternatives become cost-competitive – either because their costs fall or because the cost of offsets rises as the economy approaches net zero – the role of gas and liquid fuels will fade away.[150]

Governments will need to plan for how and when to eliminate the last remaining emissions from the NEM. They have a role to play in supporting the development of zero-emissions firming technologies, from supporting research, development, and early-stage deployment, to ensuring the right policy framework for large-scale deployment. If and when it becomes clear that achieving zero-emissions electricity is a lower-cost way to meet Australia's climate commitments and electricity consumers' needs than using offsets, then it would be appropriate for governments to target zero-emissions and limit offset use in the electricity sector.

4.3 Value the NEM and facilitate new transmission investment

Actions by some states in recent years, including renewable energy programs and derogations from the national rules, reflect frustration with the governance and regulatory structure of the NEM. Yet, this report shows the value of the interconnected NEM to all member states and the ACT. More transmission, both between and within states, is needed to support high renewable penetration. It is in the interests of all jurisdictions to recommit to the NEM. However, the states are right to demand improvements.

The ESB has facilitated improvements in response to state and industry frustration with the slow pace of change. AEMO's Integrated System Plan and actions by the Federal Government and some states to work together to speed-up selected transmission investments also suggest that cooperation is possible.[151]

Some governments are also dissatisfied with the current allocation of costs for interconnector upgrades. Historically the costs have been split between the states which are linked by the interconnector. But there is evidence that the benefits of interconnection spread beyond the two jurisdictions that are linked.[152] The ESB has been asked to consider whether the present method of paying for interconnectors should be replaced with a 'beneficiary-pays' model.[153] Governments should resolve this issue quickly, recognising the value to the entire NEM of interconnector upgrades that pass a rigorous cost-benefit analysis. Greater connection between NEM members would also increase competition, to the benefit of consumers.[154]

Finally, governments should engage with the ESB to develop a common framework for implementing renewable energy zones, rather than pursuing uncoordinated policies.

149. Wood and Dundas (2020, Chapter 4).
150. Unless the economics of carbon capture and storage improve substantially (see Section 3.2.5 on page 33).
151. See, for example, Morrison et al (2020).
152. TasNetworks (2020, pp. 13–14).
153. ESB (2020).
154. ACCC (2003), as cited in Mountain and Swier (2003); Sims (2003).

Appendix A: Technical appendix

For this report, Grattan Institute built an economic model of the NEM to test different mixes of generation technologies that could reliably meet future electricity demand in all sorts of weather.[155] The Grattan model uses many of the inputs published alongside AEMO's 2020 Integrated System Plan (ISP).

The Grattan model is designed to give policy makers insight into the cost, reliability, and emissions implications of different technology mixes in the NEM. Unlike AEMO's ISP, it abstracts away from the exact path over the next few decades, and instead considers how the system might look in the long run.

This appendix explains the data and methodology underpinning the analysis in this report. A summary of the model is provided in Box 8 on the following page.

A.1 Model inputs

Grattan's NEM model requires the following inputs:

1. A specific mix of generation capacity, split by technology and location;[156]
2. A representation of the transmission network (Figure A.3 on page 50), and the capacity of interconnectors (the power lines that connect states, enabling power to be transferred between NEM regions);
3. An hourly forecast of wind and solar availability in each renewable energy zone (REZ), and an hourly forecast of demand in each state;[157]
4. A number of technical assumptions about how different types of plant operate; and
5. A number of economic assumptions about capital costs of each technology, regional cost factors, asset lives, the cost of financing assets,[158] and fuel prices.

This section describes each of these inputs in turn.

A.1.1 Generation technologies

The only technologies included in the model are wind, solar, black coal, brown coal, gas, hydro, and storage. The model needs to know how much capacity of each technology is required in each state.[159]

Wind is primarily onshore – while one REZ (Victoria's Gippsland) includes offshore wind, the significantly higher costs of building offshore mean that the resource is generally not developed in the modelling. 'Solar' means single-axis tracking solar PV. Wind and solar capacities were provided at the state level and then split among the lowest-cost REZs first, up to the build limits provided in the ISP.[160] The allocations

155. The Grattan model is implemented in the C++ and R programming languages: R Core Team (2020), Wickham et al (2019) and Eddelbuettel and François (2011).

156. Wind and solar capacities are specific to renewable energy zones (REZs): their boundaries are described in AEMO (2020e). Other technology capacities are specific to each NEM region. NEM regions are closely aligned with state boundaries. The ACT sits inside the NSW NEM region.

157. Technically each NEM region.

158. The 'weighted average cost of capital' (WACC).

159. To reduce the number of model parameters, Tasmania is assumed to be supplied with only hydro and wind.

160. By lowest-cost, we mean REZs with the lowest expected cost of supplying each unit of electricity (sometimes termed the 'levelised cost of electricity'). This is influenced both by the cost of building in the REZ and by the quality of the resource.

Box 8: A brief summary of Grattan's NEM model

Grattan's model of the NEM simulates how different electricity generators might be dispatched in the future, responding to hourly fluctuations in demand and renewable power availability. This is known as a 'time-sequential model', and it is necessary for testing the reliability of a future electricity system.

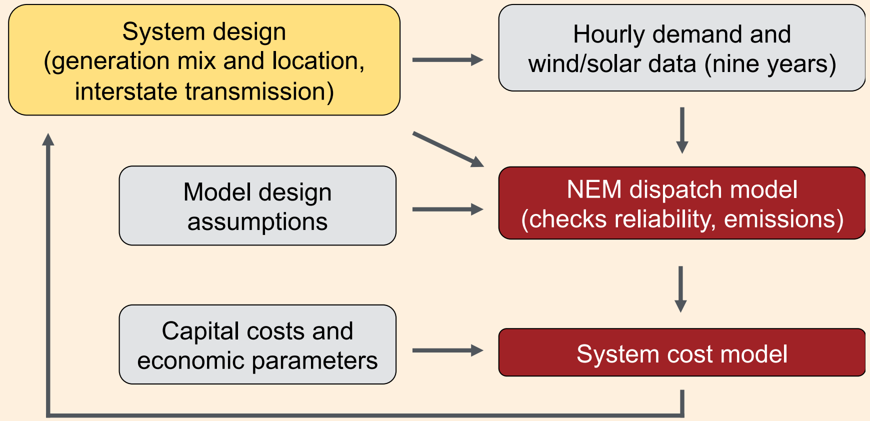
The main input to the model is a mix of generation technologies – such as black coal, brown coal, gas, wind, solar, hydro, and storage (pumped hydro and batteries). The model needs to know what capacity of each technology is built in each state of the NEM, and in the case of wind and solar, *where* in the state they are built.[a]

The model also requires hourly demand, wind, and solar data; we used nine versions of the financial year 2040-41, sourced from AEMO's ISP.[b] We chose this year because the analysis is explicitly designed to help understand the implications of aiming for different technologies mixes in the NEM in the long run. The analysis is about the destination; it does not try to design in detail the optimal pathway to get there, nor does it try to anticipate or factor in government policies or investments over the next few years.

The model checks whether demand could be met reliably over each hour of the nine synthetic future years, and computes the cost of doing so. This includes running costs, such as operations and maintenance, and fuel costs for coal and gas-fired generators. It also includes the capital cost of building all generation, spread out over each asset's life – this is known as the 'Greenfields' approach. This approach determines the long-run cost of supplying electricity, reflecting the reality that assets age and eventually need to be replaced. The cost of each technology is based largely on CSIRO estimates for the year 2040.[c] If additional transmission is modelled, the cost of these upgrades is also included.

As each model was run, we fed insights into subsequent system designs (Figure A.1). This is an informal optimisation approach, generating approximate least-cost system designs.

Figure A.1: Grattan's NEM model



a. Wind and solar in the model can be built in any of 35 renewable energy zones (REZs), each with its own weather patterns.
b. The model uses AEMO's 'High DER' (distributed energy resources) scenario demand projections, rather than the standard 'Central' scenario. See Appendix A.1.3 on page 50 for justification. The High DER scenario shares the same economic assumptions as AEMO's 'Central' scenario.
c. Graham et al (2020a); and AEMO (2020a).

were then manually over-ridden in subsequent runs where it was clear that a particularly diverse but higher-cost resource offered better value to the system.

Black coal is modelled in NSW and Queensland. Brown coal is modelled in Victoria. No coal is assumed in either SA or Tasmania.

We considered two types of gas plant: combined cycle gas turbines (CCGTs) and peaking gas (which includes the open cycle gas turbine technology, or OCGT). OCGT technology is simpler: hot gas drives a turbine to make power. But it is less efficient than CCGT, because lots of energy is wasted. CCGTs are more expensive and complex to build, but they capture some of the wasted energy, using it to heat water and drive a steam turbine.

To be conservative, we assumed existing hydro plants dispatch only as much electricity each month as they did historically, minus a climate adjustment factor to account for the drying effects of climate change in Australia.[161] The monthly constraint also ensures any power generated as a result of water releases for seasonal irrigation is captured. No additional hydro resources are assumed to be developed, though it is assumed that in some scenarios an extra 390MW of hydro plant capacity is added in Tasmania, using existing reservoirs.[162]

The storage technologies include batteries and pumped hydro. In principle, these technologies can store minutes', hours', or days' worth of power. Only 2-, 4-, and 8-hour batteries have been included, and 24- and 48-hour pumped hydro. Snowy Hydro 2.0 has not been explicitly included, due to the complex hydrological interactions it will have with the existing Snowy Hydro system (see Box 4 on page 21).

161. AEMO (2020a).

162. AEMO anticipates a 390MW hydro capacity upgrade in the 'Central' and 'High DER' ISP scenarios but not the 'Slow Change' scenario; as such, the upgrade is assumed in the high-renewables scenarios but not the 'keep coal' scenario: AEMO (2020g).

Nuclear power is excluded due to the legislative prohibition on nuclear power in Australia, and to its high capital costs.[163] If the economics of small modular reactors improve more quickly than expected, and social license and legislative issues are overcome, then nuclear energy may have a role in future.

Solar thermal, geothermal, wave, and other more speculative renewable technologies have also been excluded due to cost and lack of data.[164] Hydrogen fuel cells or biomass have not been modelled explicitly; Section 3.2.5 on page 33 outlines why these technologies may not be economic for some time.

The approximate lowest-cost capacity mixes for each scenario are shown in Figure A.2 on the following page, broken down by state.

A.1.2 How we modelled the transmission network

We modelled the transmission network as a series of hubs and spokes. Each NEM region contains a hub where all demand and non-renewable energy generation is assumed to occur. All utility-scale variable renewable energy generation is assumed to occur in REZs, as shown in Figure A.3 on page 50. Losses are incurred as power is transmitted from REZs to demand centres.

Within states, transmission to REZs was built as needed to accommodate their specific wind and solar capacities. These were assumed to be separate connections from interconnectors, to avoid congestion on either network. Some more-remote REZs are assumed to branch off a backbone of less-remote REZs – to build more transmission capacity to one of these REZs, the entire backbone needed strengthening.[165]

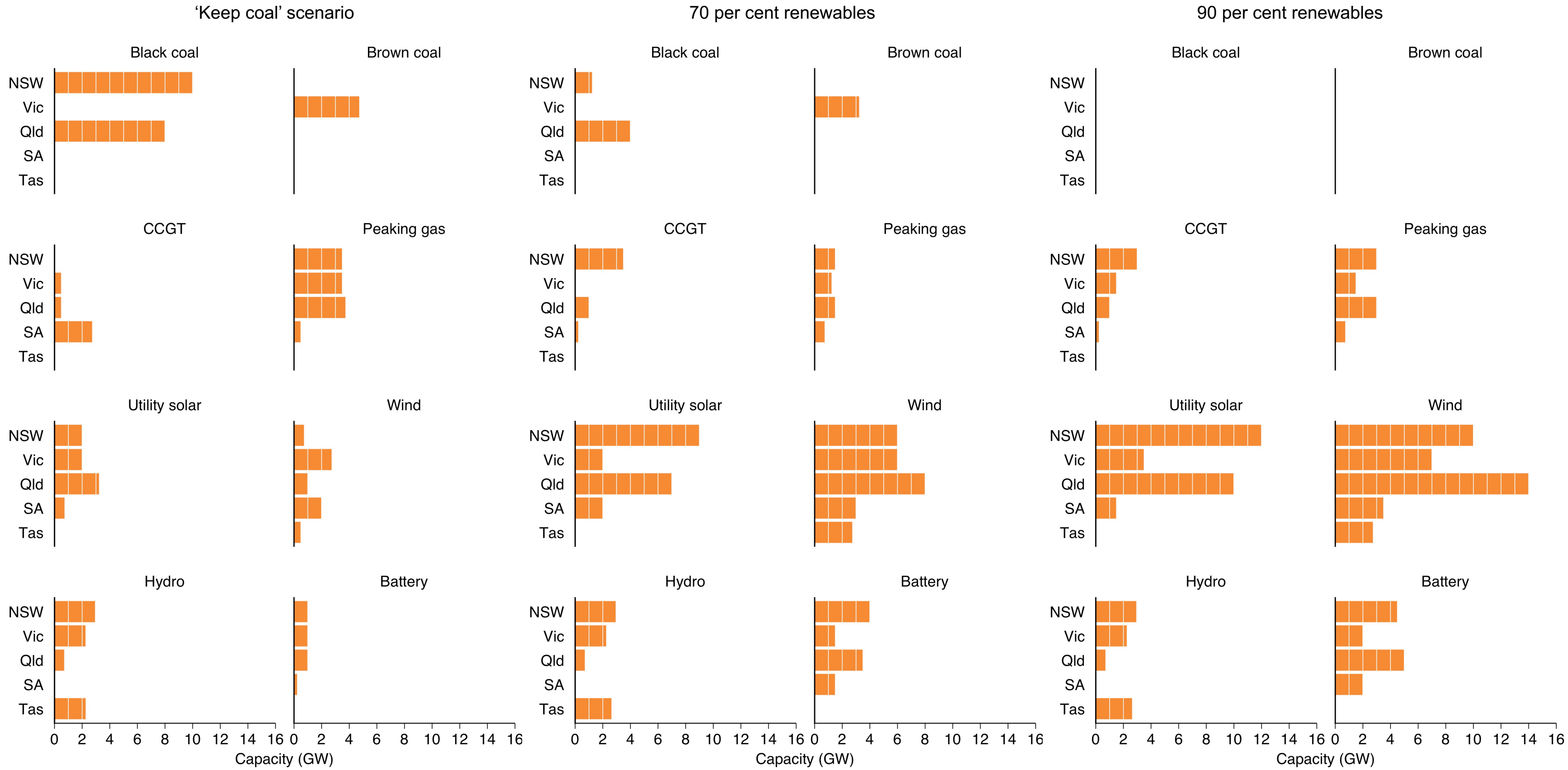
163. Graham et al (2020b, pp. 63–65); and AEMO (2019a, p. 35).

164. AEMO (2019a, pp. 35–36).

165. This modelling approach draws on group constraints as outlined in AEMO (2020a, 'Build limits' Sheet).

Figure A.2: Detailed capacity mixes by state

Capacity by scenario by state



Notes: CCGT = combined cycle gas turbines. Most generation types (excluding hydro) were modelled in multiples of 250MW, 500MW, or 1GW. Pumped hydro was tested in the mainland NEM states but was not found to reduce system unit cost.

Different amounts of interconnector capacity were tested across scenarios, as explained in Section 2.1.1 on page 16. Some power is assumed to be lost over the interconnectors.[166] Instead of modelling a direct SA-NSW link, the model assumes a SA-Vic-NSW connection, with the SA-NSW link capacity added to each of the SA-Vic and Vic-NSW link capacities.[167]

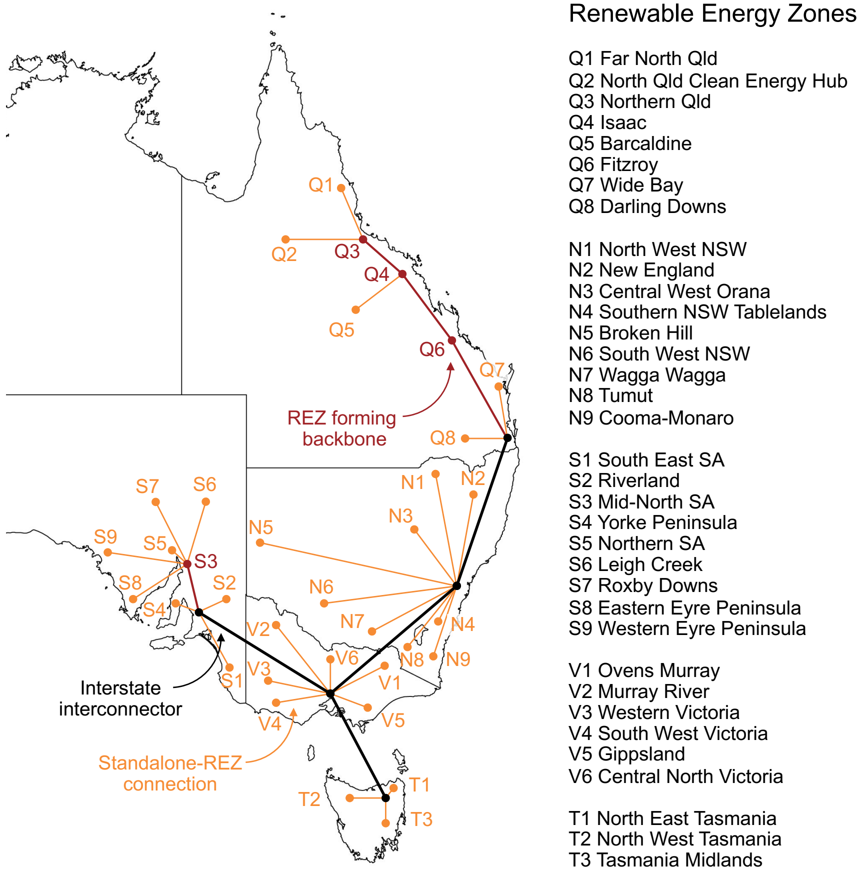
The Vic-NSW link capacity was also reduced depending on the output of the existing Snowy Hydro scheme in each hour, to reflect both real-world constraints today and future constraints after upgrades.[168]

A.1.3 Hourly data

AEMO's ISP includes rich sources of electricity demand, wind, and solar data.[169] AEMO has used nine years of historical demand and weather data (known as 'traces'), which span every half-hour from the 2010-11 to 2018-19 financial years, to create nine simulated versions of future years, with the demand traces adjusted to account for future demand growth and other factors (see Figure A.4 on the next page).[170]

By basing future years on historical data, correlations between demand and weather are preserved: for example, higher demand is observed on hot days due to the extra air-conditioning load on the system. Demand data are provided for each NEM region (essentially the states

Figure A.3: Stylised representation of the transmission network and Renewable Energy Zones used in this report



Notes: Backbone links (in red) need to be upgraded to accommodate all upstream capacity; the cost of expanding transmission to each REZ and along each backbone is taken from AEMO (2020a).

166. The loss factor was estimated from the equations in AEMO (2020f, pp. 42–48). To simplify the calculation, a single loss factor was assumed for each direction of each interstate link. These were determined by using the loss factor at maximum flow and average demand levels. This means anywhere between 8-to-17 per cent of energy was lost when transferred between states. Upgraded interconnectors were assumed to have the same loss factors.
167. This approach is consistent with AEMO (2019a, p. 56).
168. With HumeLink and VNI West in place, the following constraint would apply: VIC to NSW forward direction flow + NSW to SA reverse direction flow + Upper/Lower Tumut generation < 5,100MW: AEMO (2020a).
169. AEMO (2020h).
170. AEMO (2019c).

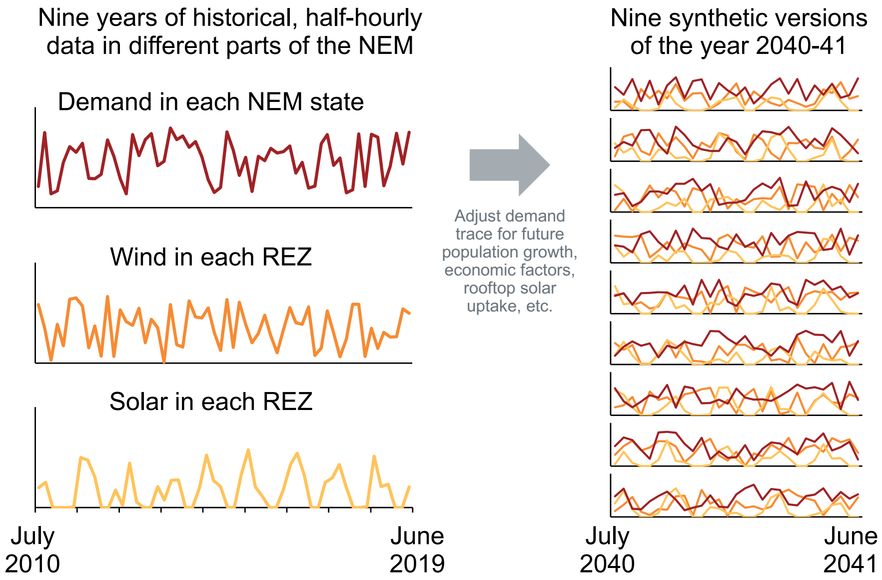
of Queensland, NSW, Victoria, SA, and Tasmania);[171] wind and solar data are provided for each of the 35 renewable energy zones (REZs) that AEMO has identified across the NEM (Figure A.3 on the preceding page).

This report uses the demand, wind, and solar traces for the financial year 2040-41. There are nine traces for that financial year – best conceptualised as nine possible versions of what 2040-41 might look like – each corresponding to one of the nine historical reference years (see Figure A.4). The Grattan model converts AEMO's half-hourly data to hourly data, and tests future system designs against the nine versions of 2040-41. Using nearly a decade of data is vital to understanding how the reliability of the system will fare in different weather conditions, because some years have much hotter summers or less windy winters than others.

To project future demand, AEMO has re-scaled historical demand to reflect future changes such as population growth, economic growth, climate impacts, and uptake of distributed energy resources (DER) – rooftop solar, batteries, and electric vehicles.[172] Grattan's model uses AEMO's 'High DER' projections for the year 2040, because recently observed rates of rooftop solar uptake best fit this scenario.[173]

171. The ACT is included in NSW. Some regional communities in these states are not connected to the NEM.
172. AEMO (2019c).
173. Over the two years from FY2019-20 to 2020-21, AEMO's Central scenario forecast an average of 0.9GW of new rooftop solar across the NEM each year, whereas the High DER scenario forecast 1.8GW each year: AEMO (2020a). In fact, in 2020, more than 2.5GW of rooftop solar was added in the NEM states, with similar growth anticipated for the next four years: CER (2021b, Figure 20). Uptake of behind-the-meter battery (or 'disaggregated embedded energy storage') is forecast to be 150MWh and 250MWh per year for the Central and High DER scenarios respectively over FY2019-20 and 2020-21; SunWiz (2021) estimates that 341MWh were deployed Australia-wide in 2020.

Figure A.4: AEMO uses nine years of historical demand, wind, and solar data to derive several example datasets for a future year



Source: Grattan analysis of AEMO (2019c).

A.1.4 Assumptions about plant operation

The Grattan model uses several factors to estimate what the output from different electricity generators might be under different conditions. These factors are taken from the 2020 ISP, and include:

- The time of year (the available capacity of thermal plants such as coal and gas are reduced during summer);
- Maintenance and outage rates;[174]

174. These are averaged across all modelled hours; a plant that is expected to be offline for maintenance 2 per cent of the time is modelled as having 2 per cent less capacity available at all times.

- A climate factor, which reduces the amount of energy available from hydro reservoirs by 10.6 per cent on the mainland and 5.9 per cent in Tasmania;
- The 'heat rates' for thermal plants, which describe how much fuel needs to be consumed to produce each unit of electricity; and
- 'Auxiliary load', which is how much power is used at the plant to power its own needs rather than sent out to meet consumer demand.

A.1.5 Economic assumptions

The Grattan model's economic assumptions are largely drawn from the 2020 ISP.

The capital cost of each technology is taken from the ISP's Central scenario cost projections for the 2040-41 financial year (Table A.1), which themselves are largely based on CSIRO's GenCost study.[175] The cost of 8-hour batteries is not included in the ISP; we took this directly from Graham et al (2020a). The ISP is also the source of fixed and variable operations and maintenance (O&M) costs for each technology, as well as the cost of the various interconnector upgrades considered in Table 2.1 on page 16. All costs are reported in real dollars, inflation-adjusted to 2019.

The capital and O&M costs of each technology are also adjusted to account for regional differences. These regional adjustment factors have been taken from the ISP.[176]

175. Graham et al (2020a).
176. For non-renewable energy generation, all assets are assumed to be located in the 'low' cost zone within each state; for variable renewable energy, each REZ is located in a specific cost zone. This is a conservative assumption that slightly disadvantages high variable renewable energy scenarios.

Table A.1: Future capital costs (before regional adjustment) for various technologies

Technology	Capital cost ($/kW, real 2019)
Black coal (supercritical PC)	3,204
Brown coal (supercritical PC)	4,945
CCGT	1,642
OCGT	1,371
Wind	1,457
Offshore wind	5,583
Large-scale solar PV	654
Battery storage (2hrs storage)	490
Battery storage (4hrs storage)	773
Battery storage (8hrs storage)	1,024
Pumped hydro (24hrs storage)	3,323 (see notes)
Pumped hydro (48hrs storage)	4,993 (see notes)

Notes: 'PC' means 'pulverised coal', 'CCGT' is 'combined cycle gas turbine', 'OCGT' is 'open cycle gas turbine', and 'PV' is 'photovoltaic'. Capital cost projections are for the 2040-41 financial year. All capital costs vary by location; regional adjustment factors are provided in AEMO (2020a) and were used in the modelling. In particular, pumped hydro costs vary significantly between states; the Victorian costs are presented here, but state-specific values were used.

Sources: AEMO (2020a) and Graham et al (2020a).

To determine the annual cost of building and maintaining assets, it's necessary to amortise the capital cost over the life of the asset. To do this, two parameters are needed: the asset life, and the cost of financing the asset (known as the 'weighted average cost of capital', or WACC). The analysis in this report uses the economic life of assets as reported in the ISP,[177] and a real WACC of 6 per cent for all projects.[178]

177. The 'economic life' is the time-frame over which investors would be expecting to recoup the cost of building the asset: AEMO (2020a). It has also been described by GHD (2018, p. 19) as the 'design life' of a plant, or the time over which it is expected to operate within its specified operating parameters.
178. The ISP uses a 5.9 per cent WACC in most scenarios.

Sensitivity analysis in Appendix A.4 on page 55 demonstrates the effect of amortising over the technical life of an asset (which is longer than the economic life), or choosing a lower WACC.

The ISP also provides the cost of coal and gas in 2040-41, for different regions of the NEM. The gas price is also split by technology, because CCGT plants are likely to secure larger contracts and lower prices than peaking plants.

A.2 The dispatch model

Grattan's model is a 'time-sequential model', which means it acts like a system operator to dispatch lowest-cost sources of supply to meet demand for each hour of the nine synthetic years (see Box 9).

The model tries to balance computation speed with accuracy and conservatism in how the NEM is portrayed. For instance, existing hydro resources are constrained in how they can operate (Box 10 on the following page).

The model dispatches variable renewable energy first to try to meet demand within each state.[179] If there is unmet demand in any state, and surplus variable renewable energy in another state, then the interstate transmission network is used as much as possible to fill the gap. If unmet demand remains, other technologies further down the merit order are used in the same way: brown coal first, then black coal, certain storage units,[180] CCGT, peaking gas, and lastly the remaining types of storage.

179. Technically to meet demand net of any hydro dispatched that hour; hydro is pre-dispatched as described in Box 10 on the following page.
180. The position of storage in the merit order depends on a number of factors, including how full the storage is, and whether the subsequent day or week appear to have high demand and low variable renewable energy output.

Box 9: The merit order

In the NEM, generators bid a price at which they are willing to supply power each five minutes. AEMO then ranks these bids lowest to highest – this is known as the 'merit order'. The cheapest generators are ordered to dispatch power, up to the point where all demand is met. Generators that dispatch power are paid a price per unit of energy equal to the bid of the most expensive dispatched generator.[a]

The Grattan model does not include a bidding model, because this would add significant complexity due to the need to realistically portray behaviour of individual market participants. Instead, most technologies are ranked according to what it costs them to supply an additional unit of power: this is known as their short-run marginal cost.

For example, wind and solar do not use any fuel, so it is essentially costless for them to operate: they are always dispatched first. A coal or gas plant must pay for the fuel it burns, and coal is cheaper than gas per unit of energy, so coal would be dispatched ahead of gas in the model.

The existence of storage technologies in the model complicates the story – a battery or pumped hydro owner has limited energy reserves, and must decide whether to sell or buy power now or wait until the price is higher or lower in a later trading period. Storage behaviour is therefore represented stylistically, with generators changing their behaviour depending on the amount of power in reserve, the needs of the system, and the demand-supply balance forecast over the next 24 hours.

a. There is an added complication due to 'half-hour settlement', a practice that will be phased out in October 2021: AEMC (2021).

Coal is assumed to operate at a minimum level of output at all times – it is not allowed to switch off.[181] But it is allowed to ramp freely between its minimum and maximum level of output each hour. In reality, coal plants can shut down, but restarting is slow and costly.[182] And although new coal plants are able to ramp between their minimum and maximum output within an hour,[183] they are not able to do so on a five-minute basis. As such, real coal plants may meet less demand than modelled in this report. Similarly, CCGTs are slower to start up than peaking gas or storage alternatives; the analysis in this report therefore overvalues CCGTs relative to more flexible electricity sources.

Surplus variable renewable energy (plus the minimum coal output) is assumed to be stored whenever possible; any spare interconnector capacity is used to transfer this surplus power to where it can be stored. Ahead of particularly challenging days (high demand, low variable renewable energy output) or challenging weeks, storage units within a state may also pre-fill with available fossil energy, to ensure there's enough capacity to ride through the difficult conditions. Restricting the behaviour of storage operators so that they respond only to day-ahead and week-ahead signals attempts to better reflect the real-world uncertainty that these operators will face.

When using forecasts, it is not possible to make claims about reliability *with certainty*. But if the mix of technologies is able to supply demand each hour for the nine synthetic years, we can be more confident that it would supply power with acceptable reliability in most other years

181. This level is 30 per cent of nominal capacity for black coal and 50 per cent for brown coal, reflecting a wide range of available estimates of the minimum stable generation level for each type of plant: Calabria and Tremaine (2020, p. 27), Aurecon (2020b, p. 17), Frontier Economics (2015, p. 28) and GHD (2018, pp. 47–52).
182. AEMO (2020a).
183. Assuming minimum stable output of a 750MW unit is 30 per cent of unit capacity and a unit can ramp at 9MW per minute: GHD (2018, p. 52) and AEMO (2020a).

Box 10: How hydro is assumed to operate

When modelling July 2040 using the historical demand, wind, and solar patterns from a particular month – say July 2010 – hydro is assumed to produce as much energy in the modelled month as it did historically, minus a loss due to a potentially drier climate.

In reality, hydro operators are not constrained by monthly allowances. So long as there is sufficient energy in reserve, a future operator may choose to release more energy in a high-demand month (such as July) than was done historically. But this conservative approach allowed the model to retain some real world constraints in a stylised way: the monthly limit provides a proxy for the constraints hydro operators face due to limited inflow and seasonal irrigation demands.

The dispatch behaviour of hydro is also stylised. To avoid the need to keep track of how much energy is in each reservoir in the NEM – and the flows between reservoirs in complex systems such as the Snowy Hydro scheme and the Tasmanian network – the model 'pre-dispatches' hydro. This means that the model determines the differences between variable renewable energy supply and consumer demand each hour of each month, and uses the available hydro to minimise energy deficits. This is an example of the foresight discussed in Section 2.1.3 on page 19, but it is less-than-perfect: hydro operators are assumed to have knowledge only of the next month's data, not the entire year, and they are assumed to respond to local conditions within their state only, not accounting for the availability of variable renewable energy imports from other states.[a]

a. In addition, generators with deeper storage (such as conventional hydro) have less distorted modelled outcomes when using perfect foresight: Hydro Tasmania (2019, pp. 5–6).

too.[184] The traces published by AEMO also include adjustments to make each year's demand patterns look like a 1-in-10-year challenge, rather than simply a typical year's pattern.[185] On top of this, the model determines how much 'buffer' capacity was available each hour – how much generation could fail before a state would have unmet demand. All results presented ensure that there is about a 15 per cent capacity buffer for each state in each hour – this helps to account for the fact that the model does not include random plant outages.

A.3 The cost model

The Grattan model calculates the system unit cost in dollars per MWh of consumer demand met.[186] This is sometimes described as the 'levelised system cost'. This calculation considers the capital and running costs of generation and the costs of building new transmission.[187] Existing transmission is not included because it does not vary between scenarios; likewise, the distribution network is excluded.

The capital costs of each form of technology are amortised over the asset's life. Effectively, this is like building the NEM from scratch overnight at some point in the future, even though we notionally model 2040 (when there may be some existing coal, gas, and other generation plants).

This is called the 'Greenfields' approach.[188] While abstract, this approach tells us the long-run cost of the system for a given plant mix. That is to say, imagine keeping today's plant mix forever. Eventually, the maintenance on old units would be so expensive that it would be more efficient to rebuild them – incurring capital costs again (Section 2.2.1 on page 22). This approach ignores the legacy generation assets we have today, to consider what mixes of technologies the NEM will ultimately need in the future.

However, to avoid estimating the capital costs of replacing existing hydro plants – which are often complex, bespoke-engineered systems – all hydro is excluded from the system unit cost calculation. To compensate for this, any demand satisfied by hydro power is also subtracted from the denominator of the system unit cost. Due to the dominance of hydro power in Tasmania, all Tasmanian capital costs and demand are also netted off the system unit cost – this is likely to have only a small impact on the results for the rest of the NEM. But interconnector upgrades between Victoria and Tasmania are included in the system unit cost.

A.4 Assumptions and sensitivity analysis

To make modelling feasible, many assumptions must be made. These could be about parameter values, or constraints that reduce the options the model can explore. In general, the assumptions made in this modelling tend to add to system unit cost, rather than reduce it. Appendix A.4.1 lists many of the assumptions that would affect system unit cost in this analysis. Appendix A.4.2 considers the effect of changing two of the most important parameters: the WACC (weighted

184. Provided that there are no catastrophic technical failures.
185. This adjustment involves simulating thousands of possible demand traces for a given year, extracting seasonal maximum demand values, and setting maxima in the final trace equal to the 10th percentile: AEMO (2019c, pp. 38–40).
186. Costs are inflation-adjusted to 2019 dollars. 'Consumer demand' means demand satisfied by the NEM; it therefore excludes demand supplied behind-the-meter by rooftop solar panels or small-scale batteries. It also excludes demand from charging utility-scale batteries or pumped hydro.
187. A cost is also included for synchronous condensers to meet plausible system strength requirements, considering the minimum three-phase fault level required at each fault level node in the NEM: AEMO (2018, p. 3) and AEMO (2020k, p. 4). Grid-forming inverters or other technologies may be able to meet system security needs at lower cost in future; this is therefore a conservative assumption.
188. If the asset life is assumed to be the technical life, this approach determines the 'long-run marginal cost' of electricity supply.

average cost of capital) and the plant life. Appendix A.4.3 considers the effect of cost overruns on inter-regional transmission upgrades.

A.4.1 Significant model constraints

All projected demand had to be supplied in the model – no unmet demand was allowed, nor any demand-side participation (such as an aluminium smelter voluntarily reducing demand for a few hours). In reality, these options would both be more economic at times. It's costly to build extra generation assets just to make sure there's enough power for the rarest energy shortfalls.

Transmission losses were treated simply but conservatively: a fixed ratio of power was assumed to be lost across each line of the modelled network, with the ratio based on the marginal loss factor for intrastate transmission[189] or on the loss factor at maximum flow for interstate interconnectors.[190] In reality, the relationship between loss and power is non-linear, so losses would be smaller than modelled whenever flow is below the rated capacity of the link.

The cost of extra transmission to renewable energy zones in the 'major transition' scenario is almost certainly too high. Upgrades to interstate interconnectors (as proposed in AEMO's ISP) would also unlock extra transmission capacity for renewable generation in REZs.[191] But this is not accounted for in the modelling. In addition, any REZs through which an interconnector passes were assumed not to have any spare transmission capacity for renewable generation. This was to avoid situations where additional renewable generation causes congestion along the line, limiting interconnector capacity. These assumptions required the model to build substantially more stand-alone transmission to REZs, increasing costs more than would be expected in reality. And scenarios with more REZ generation capacity than transmission capacity were not tested, though in reality this would be the most efficient outcome despite the congestion it would create (see Section 2.2.2 on page 24).[192]

Storage and hydro both behave in stylised, sub-optimal ways in the model: in reality, owners of these assets have sophisticated strategies to try and preserve power at times to maximise output when prices are highest – and hence when the supply-demand balance is tightest.

The estimated capital cost of both black and brown coal has risen since the 2019-20 GenCost, from $3,307 and $5,104 to $4,275 and $6,599 per kW respectively.[193] But the 2019-20 GenCost values have been used.

The heat rate of thermal plants is assumed to remain the same even when plants are operating below their maximum output; this slightly underestimates the fuel consumption of each plant, widening the gap between the 'keep coal' and higher-renewables scenarios.

A.4.2 The effect of changing the WACC and plant life

The most significant parameters in this report's analysis are the WACC and plant life. Changing these significantly changes the system unit cost of each scenario. But it is unlikely to change the conclusions drawn from this report: the differences between scenarios remain robust even when using the alternative WACC and plant life values (Figure A.5 on the next page).

This simple sensitivity analysis is a useful first approach, but changing the values of certain parameters will have second-round effects on the system unit cost of each scenario. That's because under different assumptions, the least-cost plant mix for each scenario is unlikely to

189. AEMO (2020a).
190. Based on Grattan analysis of AEMO (2020f).
191. AEMO (2020a).
192. ESB (2021, p. 93).
193. Graham et al (2020b).

match the mix determined under the previous assumptions. To fully understand the effect of different assumptions, each scenario would need to be re-optimised. This is beyond the computational resources available for this report; as such, all system unit costs determined using alternative parameter values represent upper-bounds.

A.4.3 The effect of higher-than-expected costs for interconnector upgrades

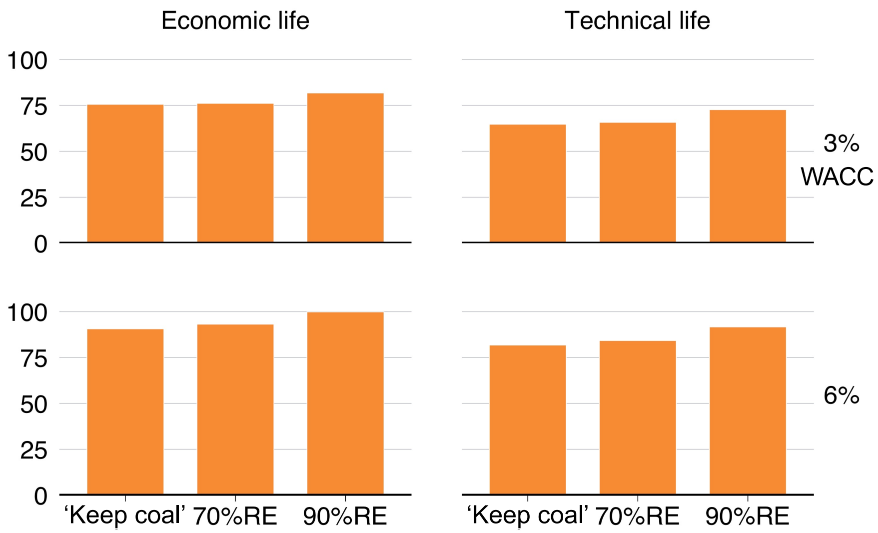
Table 2.1 on page 16 details the cost assumptions for the interconnector upgrades modelled in this report. These costs are taken from the 2020 ISP.[194] The 2020 ISP publishes a range of interconnector cost estimates, with the higher-end of estimates being 30 per cent greater than the central estimates used in both the ISP modelling and this report.

Increasing the cost of the transmission upgrades by 30 per cent would increase the system unit cost of the '70%RE' and '90%RE' scenarios by less than $2/MWh. That would mean reaching 70 per cent renewables without the full suite of interconnector upgrades would be lower-cost than building all of them.[195] But at 90 per cent renewables, the full set of interconnector upgrades would continue to offer value despite their higher cost. This means the conclusion that greater interconnection will be required to reach 90 per cent renewables at lowest cost remains robust.[196]

194. AEMO (2020a).
195. This makes the value of greater interconnection less clear. A subset of the projects – not tested in this report – may offer the lowest-cost way to achieve 70 per cent renewables. The 2020 ISP itself finds that the optimal transmission development path in the 'High DER' scenario (which would achieve about 70 per cent renewable energy share by 2040-41) would not include the HumeLink or VNI West projects.
196. Even if a subset of the projects offers greater value than the full suite, it's clear that maintaining today's level of interconnection is a *higher* cost option, and therefore at least some additional interconnector capacity should be built.

Figure A.5: The relative cost of each scenario's plant mix is similar even with different assumptions

System unit cost ($/MWh) for each scenario, using different plant life and WACC assumptions



To change this conclusion, the suite of upgrades would need to cost at least 80 per cent more than assumed. This would increase the system unit cost of the '90%RE' scenario by about $5/MWh – sufficient to make it comparable with a 90 per cent renewables system with none of the modelled upgrades.

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