The Investment Challenge

Investment in Australia's electricity generation sector to 2030

For the Australian Energy Council

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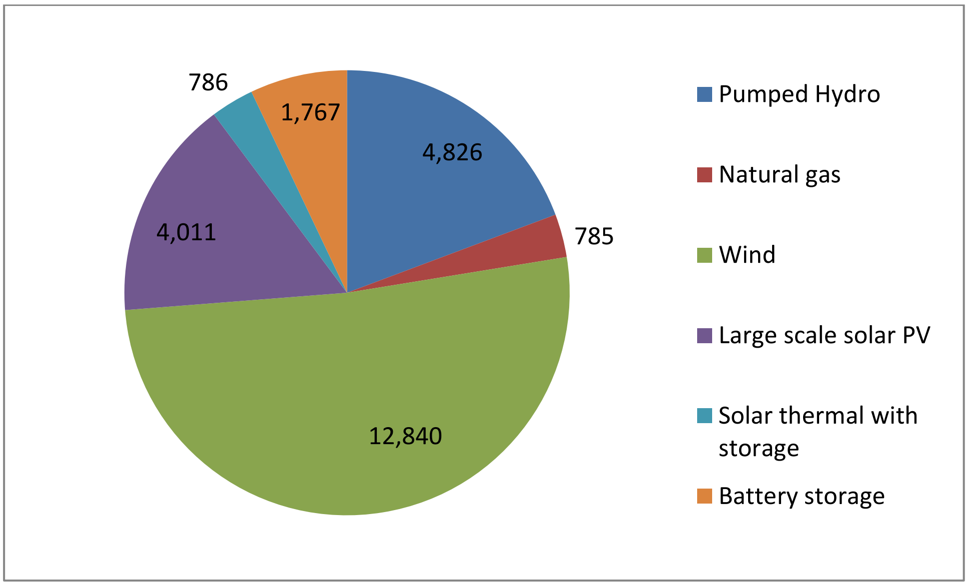
Contents

Executive Summary

Australia's electricity systems are critical to our well-being and our economy. They are going through a phase of major renewal as older coal-fired generation closes and new renewable plants are built to take their place. But this is not a like-for-like replacement, and so we will also need plant that is dispatchable, meaning it can start up or increase output at short notice so that the system supply and demand can be balanced from second to second.

This will require a significant amount of investment. Quite how much depends on a range of factors including technology costs, changes to carbon and energy policies, when older plant retires and more. It gets harder to make a meaningful estimate the further out one looks. Looking to 2030 and assuming the main policy driver is the government's proposed National Energy Guarantee, around $25 billion of investment in large scale generation is likely to be required. This will be spread over a range of renewable and non-renewable technologies, including a significant increase in storage, as shown in Figure 1.

Figure 1: Investment by technology type ($m)

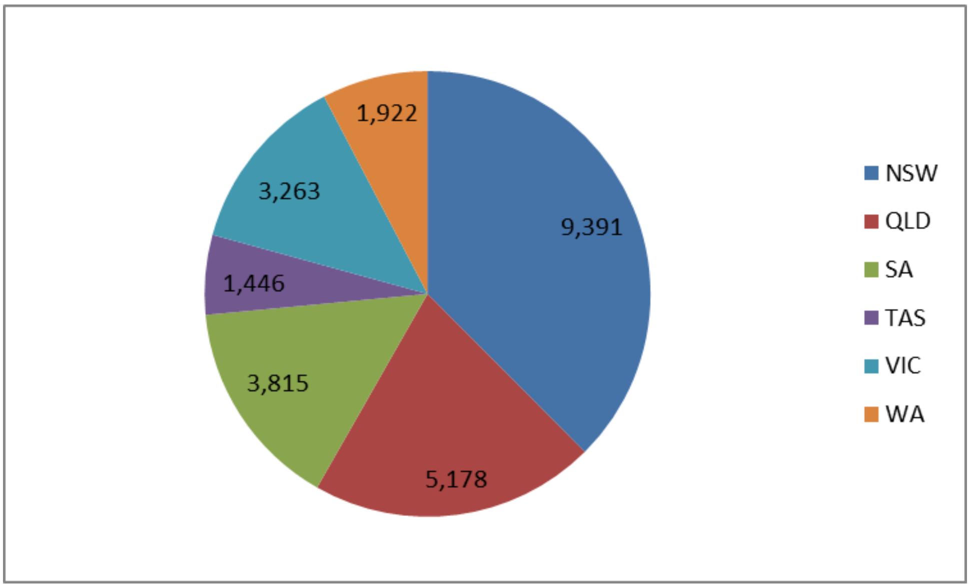


This is purely the investment required in large scale generation in Australia's two main electrical grids, the National Electricity Market (NEM: $23bn) and the Western Electricity Market (WEM: $2bn). The changing pattern of generation will also entail investment in the high voltage transmission network that transports bulk power. There will also be investment in the distribution network that delivers power to our homes and businesses and customers will also collectively invest billions in rooftop solar, batteries and other distributed energy resources. Furthermore there will be additional capital required to maintain existing assets, and of course on-going operational costs in all sectors, such as labour and fuel, which are not included here.

In addition to the NEM and the WEM, there are several smaller grids and stand-alone power stations in the remoter parts of Australia and these, too, will need further investment to continue to operate effectively and meet customers' needs.

The projected split of this investment across the states is shown in Figure 2. All states other than WA are part of the NEM.

Figure 2: Investment by state ($m)



All investment is based on the investor expecting a return on their money. It is *how* they get the return that sets this $25bn apart from the other types of investment. While transmission and distribution investment is regulated, giving their owners certainty of a return, generators earn a return by selling their output into a competitive "spot" market where the price changes every five minutes. Contrast this with expected asset lives of 40 years or more. The NEM and the WEM each allow for longer-term contracts so that both generators and electricity buyers can manage their risks, but these do not typically span the full life of the asset, and many contracts only last for a year or two. In any case, the two markets are regulatory creations themselves, and both have been subject to significant reform processes over recent years as governments and regulators grapple with the challenges of technology change or react to periods of high prices. Some of these reforms have a material impact on generator returns.

Generation is also much more affected than other types of investment by the chronic instability that has plagued Australian carbon policy. The uncertainty this creates for investors is not just limited to highly emissive generation like coal-fired plant. The return on a renewable generator is also affected by uncertainty about how their more emissions intensive competitors will be treated, and the value of storage investment depends on the overall mix of generation in the market.

So the big challenge for policy makers is ensuring that investors have sufficient confidence in the market and the overall policy settings to deliver this investment. If emissions reductions for the sector become more ambitious, then the amount of investment required only increases. Previous modelling exercises assuming greater emissions reduction and different policies to drive them resulted in estimates of $35bn (AEMO, 2016) to $71bn (Jacobs, 2016) to 2030. International capital has many options for where to invest. Even in Australia's electricity sector, generators are effectively competing with regulated networks for this capital. If the rules were changed so that investors were guaranteed returns in a similar manner to the regulated networks, then it would be easy to attract investment (as long as the returns were sufficient). But this does not make the risks disappear – it simply transfers them from the generators to customers (or taxpayers).

1 Introduction

Australia's electricity systems are critical to our well-being and our economy. They are going through a phase of major renewal as older coal-fired generation closes and new renewable plants are built to take their place. But this is not a like-for-like replacement, and so we will also need plant that is dispatchable, meaning it can start up or increase output at short notice so that the system supply and demand can be balanced from second to second.

This will require a significant amount of investment. Quite how much depends on a range of factors including technology costs, changes to carbon and energy policies, when older plant retires and demand patterns. This report estimates the investment required between now and 2030 under a set of reasonable assumptions and discusses what is required to see this investment take place and how investment requirements may differ under different assumptions.

2 Scope of analysis

Newgrange Consulting has been asked by the Australian Energy Council to broadly estimate the total generation investment requirement in Australia's two main electricity grids, the National Electricity Market (NEM) and the Western Electricity Market (WEM) from now until 2030. A key assumption is the adoption of the National Energy Guarantee (the Guarantee) with an emissions target consistent with the Commonwealth Government's Paris commitments to reduce Australia's greenhouse emissions by 26-28 per cent from 2005 levels. Other assumptions are set out below in Table 1: Analysis assumptions.

Table 1: Analysis assumptions

Item	Assumption
Large-scale renewable energy target	Existing legislated target (33TWh to 2030)
Demand	Statement of opportunities reports (AEMO, 2017), (AEMO, 2017) Neutral scenario
Fuel costs	Australian Energy Market Operator (AEMO) gas and coal price assumptions (AEMO, 2016)

Item	Assumption
State RETs	400MW Qld, 650MW VIC already committed, SA EST already committed,
Retirements	Liddell (2022)
Entry	Snowy 2.0, 2,000MW generation and pump to begin 2023-24
Emissions target	An emissions cap for the NEM of 1,352Mt CO2-e of emissions for the period 2021 to 2030 (Energy Security Board, 2017). No formal emissions cap for WEM.
Reliability requirement	Increase in contract levels by 5% Increase in reserve margin by 5%

3 Methodology and data sources

3.1 Determining the new entry in the NEM

As this exercise did not entail new energy market modelling, a reference source that reflected the key assumptions is required. The most significant constraint is the application of the Guarantee, including the emissions reduction target set by the Commonwealth. The Guarantee is a relatively new policy proposal that has not yet been legislated and its detailed design is still being consulted on (Energy Security Board, 2018). This means that there are very few examples of modelled outcomes that can be used. Frontier Economics modelled the impact of the Guarantee for the Energy Security Board late last year (Energy Security Board, 2017). The publicly released summary figures provide a reasonable starting point for assessing the likely new entry, as the assumptions are aligned with those in 2 above. Further information was obtained from recently published analysis on the Snowy 2.0 project (Marsden Jacob, 2018) and other sundry research.

3.2 Determining the new entry in the WEM

The WEM is a much smaller market than the NEM and is less frequently modelled in public reports. The most recent relevant forecast available is AEMO's 2017 WEM Statement of Opportunities. The purpose of this report is to highlight when new capacity may be required, rather than predict what will be built in response to that requirement. The demand forecast only runs to 2026/27. A few simple assumptions can be used to extend the forecast to 2030 and convert the capacity "gap" into a plausible mix of plant that will be needed to meet that gap.

The key metric is the Reserve Capacity Target, which is derived from 1-in-10 year peak demand forecasts. This represents the figure that AEMO expects to need to procure sufficient capacity from the market for. Using the peak demand growth rate for the previous few years, the RCT can be extrapolated from 5,240MW in 2026/27 through to 5,508MW in 2029/30. Given expected availability of existing plant, this suggests 701MW of new reserve capacity credits is required. Plant can qualify for reserve capacity credits to the extent it is expected to be available to meet peak demand on the hottest days of the year.

Some of the new capacity is likely to be renewable. WA retailers are liable under the LRET and so need to purchase certificates for renewable output. While there is no formal requirement for them to buy these certificates from projects within WA, the optics of WA consumers paying for renewable investment in the East has been considered undesirable by the state government, noting that the largest retailer, Synergy, is publicly owned. So it's reasonable to assume that some at least of the remaining RET requirement will be filled by projects in the WEM. AEMO has modelled three scenarios where WA meets its share of the RET via local projects (AEMO, 2017).

Table 2: Hypothetical renewables scenarios to deliver 2,200 GWh a year into the WEM

	Wind	**Solar**	**Nameplate (MW)**	**Capacity Credits (MW)**
Scenario 1	50%	50%	895.18	295.99
Scenario 2	80%	20%	802.26	244.27
Scenario 3	20%	80%	988.11	347.71

Under each of the scenarios, wind and solar meet part of the additional capacity credits required by 2030. Based on technology capital costs the cheapest way to meet the gap is likely to be via gas open cycle turbines, so this is assumed to make up the remainder of the new capacity. For the purposes of this report, scenario 1 has been used to determine the mix, but the overall investment requirement does not materially change if either of the other two scenarios is used instead.

3.3 Technology costs

The most recent estimate of technology costs available is CSIRO's electricity generation technology cost projections 2017-2050 (Hayward, 2017).This provides capital cost projections for each year from 2017-2050 in $/MW for many of the relevant technologies, including gas open cycle and combined cycle, large scale solar PV, solar thermal with storage and wind. Battery costs were expressed as $/MWh in this report, so $/MW metrics from Marsden Jacob were used for this report. Note that these are about 20 per cent higher on a $/MWh basis than CSIRO when comparing the 2017 figures.

As this exercise did not entail its own market modelling, capacity additions cannot be matched to a specific year. So even though the main data source has capital cost figures for each year, a simplified approach must be taken and so an average of the cost at the start and the end of the period was taken. For gas and wind, the costs do not change significantly across the period. Solar and battery technologies do decease materially in cost. For solar especially, the bulk of investment occurs early in the period due to the requirements of the LRET, this may result in an understatement of the costs.

Pumped hydro costs are highly project dependent and so the CSIRO did not include this technology in its report, which is generic cost estimation. The major project that will deliver new pumped hydro capacity is the upgrade of the Snowy Mountains hydroelectric system known as Snowy 2.0. This project is currently estimated to cost from $3.8bn to $4.5bn (Snowy Hydro, 2018). The mid-point of this range has been used. Marsden Jacobs had a wide range for general pumped hydro projects, and again the mid-point has been taken. The technology cost assumptions are set out below.

Table 3: Technology costs range

Technology	Capital costs, $/KW		
	2017	**2030**	**Average**
Gas combined cycle	1,501	1,496	1,499
Gas open cycle	1,025	960	993
Wind	1,950	1,801	1,876
Large scale solar PV	2,100	1,046	1,573
Solar thermal with storage	4,815	3,124	3,970
Battery storage	2,410	1,818	2,114
Technology	**lower**	**upper**	**mid-point**
Pumped hydro (Snowy 2.0)	1,900	2,250	2,075
Pumped hydro (other)	1,000	3,000	2,000

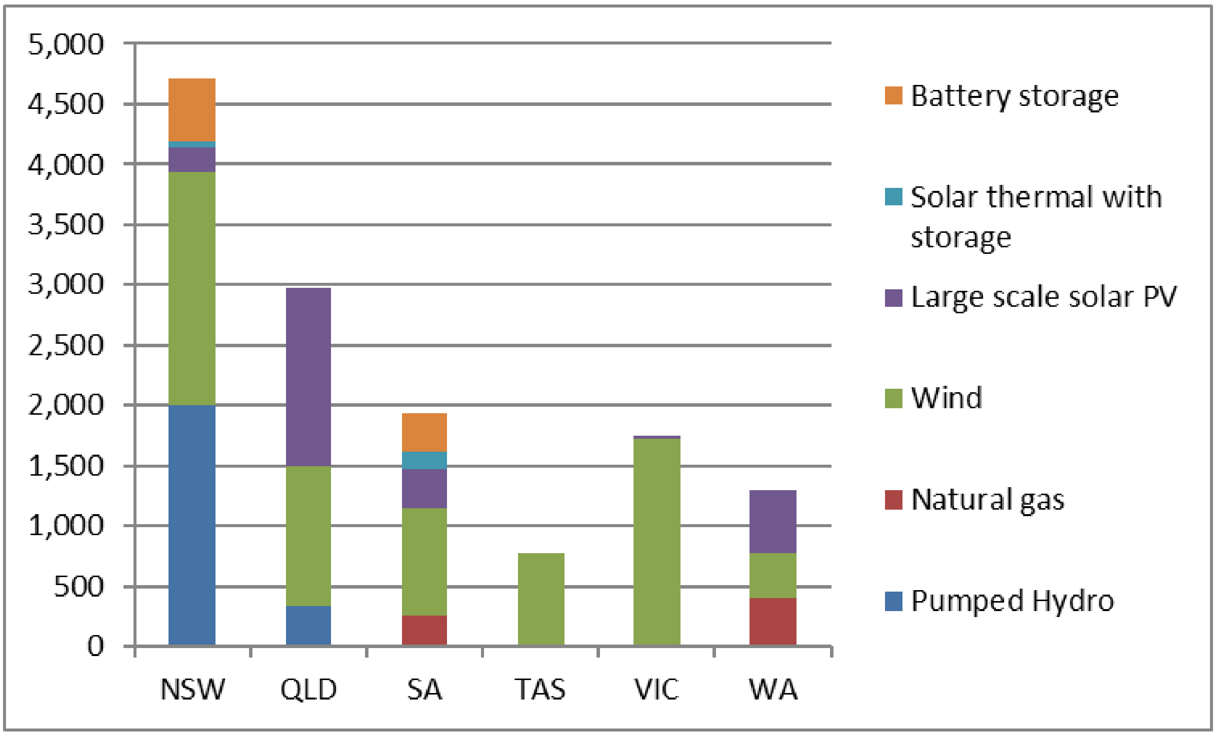
Further detail on the methodology is set out in Appendix 1: Detailed methodology and sources.

4 Results

4.1 Capacity added to 2030

Taking the inputs as described in section 3, the expected investment across the different states of the NEM and WA is 13,431MW, as shown in Figure 3 below.

Figure 3: New capacity by state (MW)

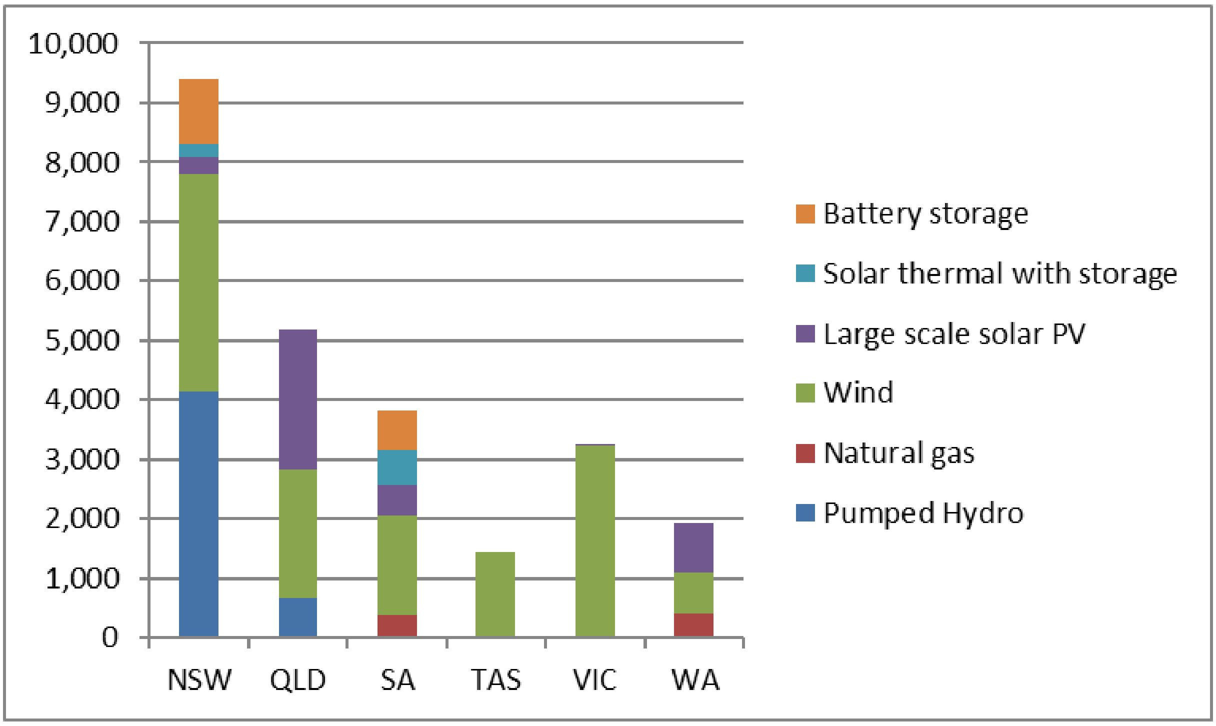


The great majority (90 per cent) of this takes place in the NEM. The investment is spread across states roughly proportionally to their existing demand; except South Australia, which has more than its share, and Victoria, which has less. Wind has the biggest share by technology of the new capacity (51 per cent), well ahead of large scale solar at 19 per cent.

4.2 Financial investment

Applying the capital cost estimates to the capacity figures above results in a required investment of $25bn. This is shown in Figure 4 below.

Figure 4: Investment by state, $m



5 The drivers of investment in electricity generation

5.1 How electricity markets deliver investment

Electricity markets balance supply and demand. Price is used as signal to denote scarcity. There are different ways to organise an electricity market, but most have two features : a real-time or near-term price signal to match supply and demand second by second and minute by minute using existing resources and a longer-term price signal to indicate when new investment is required (electricity generation can take several years to plan and build and then has an expected operational life of several decades, so it is important that there is a long-term signal for the value of new capacity). While both the NEM and the WEM still have state-owned generators, the creation of these markets was predicated on attracting private investment capital. Private investors need to be confident they will achieve a risk-adjusted return over the life of the investment.

There are effectively two ways this can take place. Investors can take merchant risk, i.e. the risk that prices may fall and so future revenues do not provide for an adequate return. Investors will want a higher average return for this risk. Or they can manage the risk through contracting with a counterparty such as a retailer or a large user. While these contracts do not tend to last the full length of the investment, even having say 10 years of revenue certainty reduces the project risk and allows for investment at a lower price.

Several energy suppliers own both retail and generation assets. This creates an internal hedge (though none of them can perfectly match their load and generation) and so they are well placed to underwrite investment. This vertical integration has been raised as potentially affecting competition, specifically in the NEM (Energy Security Board, 2018). In practice however, vertical integration has been an important vehicle for new entry into the market.

5.2 The NEM

The NEM is an energy only market based on a gross pool (all electricity is sold into and bought from the pool at the clearing price for that period) combined with a financial derivatives market that allows participants (both generators and retailers) to hedge out the risks they face from a volatile pool price. It’s effectively the strike price of these hedge contracts that provide the longer-term price signal for new investment. Of course, since the point of them is to smooth out fluctuations in the pool price, the average expected pool price informs the strike price (although there is still typically a premium).

The NEM was for many years considered a success. Highly reliable energy was delivered to customers at a low price (retail price rises were until very recently driven by increased network costs and government green schemes), while over 11,000MW of dispatchable plant was delivered. As Table 4 below shows, very little of this was built by private merchant investment, but rather built by vertically integrated entities or government owned entities[1].

[1] Note that during this period, the major owners of generation in three NEM states (NSW, Queensland, Tasmania), were governments. Queensland was the fastest growing state over the period.

Table 4: New entrant plant in the NEM 1997-2011

The source of revenue for new entrant plant for financing purposes	Capacity (MW)	Share
Govt Owned Corporation Power Purchase Agreement	2,851	25%
Government Owned Corporation as Principal Investor	3,458	30%
Sponsored by Private Vertically Integrated Entity	4,050	36%
Private Sector Merchant	982	9%
TOTAL	11,341	100%

Source: (Simshauser, 2012)

Since then, most investment has been in variable renewables. While the developers of this plant may be private merchant investors, they are not typically taking merchant risk. Instead policy design has provided near--certainty of revenue, effectively by transferring risks to the customer. In the current climate of high prices this seems unlikely to be sustainable over a growing proportion of the generation fleet.

5.3 The WEM

The WEM is a bilateral market with an energy balancing market and a capacity credit mechanism. In principle this provides more stability of revenue for a new generator, although if the annual price for the capacity credit becomes more volatile this additional stability might not persist in practice. Historically it was a fixed price, but this resulted in excess costs being transferred to consumers and so a series of reforms has commenced to make the price more sensitive to the supply of qualifying capacity.

The WEM saw demand grow faster than the NEM over the last 10 years and investors responded by investing in a range of plant, including coal, gas and renewables as well as demand response, which also qualified for capacity credits. As noted above, the capacity credit mechanism, while clearly supporting this new investment, by providing a stable revenue stream for capacity, also resulted in high cost for customers, especially as the capacity mechanism was dependent on the market operators' forecast of demand, which turned out to be well above actual peak demand outcomes for several years.

6 Sensitivity analysis

6.1 What drives different outcomes

A number of factors play an important role in determining both the overall level and the mix of investment. These include:

- Carbon policy
- Technology costs
- Other resources such as transmission or demand response
- Changes in demand
- Policy uncertainty

These are explored further below.

6.2 Carbon policy

Carbon policy can affect the level of and mix of investment in two ways – by the strength of the emissions reduction target and by the instrument used to drive policy.

6.2.1 The emissions reduction target

This has the potential to be a highly significant variance. The 2016 NTNDP modelled a 45 per cent carbon reduction by 2030 from 2005 levels as an alternative scenario to the base case, which was predicated on a 26-28 per cent reduction. Meeting this stronger target required an additional $11bn in investment or a 50 per cent increase on the base case (AEMO, 2016). Essentially tougher carbon targets require highly emissive coal plant to retire earlier, which in turns mean more investment in new low/zero emissions plant is required to meet demand.

6.2.2 The policy instrument

There are many ways to reduce emissions in the sector. Australia has tried or considered many of them at either jurisdictional or national level, including carbon tax, cap and trade, renewable energy targets, feed-in tariffs, emissions intensity schemes and regulated closure as well as the current proposal of the Guarantee. One of the most comprehensive companions was the Climate Change Authority (CCA's) Special review electricity research report (CCA, 2016). This compared seven different policy options as well as multiple sensitivities. The modelling exercise ran to 2050 under a constraint of almost full decarbonisation of the sector. Accordingly, investment levels were very high under all policy options. While capital investment was not a specific metric published in the report, if one uses total resource costs as a proxy (noting this also incorporates fuel and operating costs), then cap and trade has the lowest costs. This reflects the greater economic efficiency of a market instrument over a technology pull policy such as a renewable energy target, or a regulatory approach such as regulated closure of coal plant.

6.3 Technology costs

Changes in technology costs can have two impacts. Lower technology costs will mean that investment in dollar terms is lower for a given amount of capacity. However lower costs can mean that investment becomes viable at lower prices, and so may lead to more capacity. The converse of course applies for higher technology costs. Changes in the relative costs of different technologies will change the mix of investment.

6.4 Other resources

Some other types of investments are substitutes, partially or wholly, for generation investment. Transmission investment can reduce the need for generation investment as regional constraints are eased. Where this is the cheapest option, it is the right choice. In practice the very different nature of how transmission is funded (regulated investment test and then full recovery) versus generation (market risk) means that is hard to make an effective comparison between the two.

Demand response has come into more focus recently as an alternative to peaking generation or other flexible resources. Demand response may not require significant investment, but customers who offer demand response will want to be well compensated for forgoing consumption.

6.5 Demand patterns

The other way to model the impact of demand response is to adjust peak demand forecasts. Most distributed resources, including rooftop PV and small-scale batteries are modelled as reductions in demand. Demand can change for other reasons, such as the rate of economic growth, specific new large users (or closures of existing large users), or energy efficiency initiatives. In general a reduction in either peak demand or consumption will reduce the amount of investment required and vice versa.

6.6 Policy uncertainty and the cost of capital

Policy uncertainty can be a significant inhibitor to investment. Renewable investment stalled during the period the LRET was under review by the federal government in 2014-15, and then picked up once the revised target was legislated. There has been very little other investment in the NEM in recent years given uncertainty over carbon pricing policy. Soft demand may also have contributed to this lack of investment.

Policy uncertainty will lead to investors requiring a higher return on their capital as the predictability of their revenue is diminished. So while a higher cost of capital will not affect the capital cost of a given project it will lead to fewer projects going ahead than otherwise and a lower level of investment overall.

7 Conclusion

Investment in Australian electricity generation cannot be taken for granted. Investors require risk adjusted returns and the risks of investment in electricity generation under chronic carbon policy uncertainty are material. The uncertainty this creates for investors is not just limited to highly emissive generation like coal-fired plant. The return on a renewable generator is also affected by uncertainty about how their more emissions intensive competitors will be treated, and the value of storage investment depends on the overall mix of generation in the market. While some of the $25bn projected for the sector between now and 2020 is already committed under the RET and state renewable targets, more investments will be required to meet both emissions constraints and reliability requirements. New investments also put downward pressure on wholesale prices, which have been running at elevated levels in the NEM following the retirement of Hazelwood in 2017. International capital has many options for where to invest. Even in Australia’s electricity sector, generators are effectively competing with regulated networks for this capital. This does not mean that offering guaranteed returns is a solution – this would unwind the capital discipline that the market has brought to bear on the sector. It does mean that policymakers need to understand the value of stability to the sector – and ultimately to its customers.

Appendix 1: Detailed methodology and sources

As set out in 3.1 above, the primary source of data for expected new capacity in the NEM is analysis carried out for the Energy Security Board by Frontier Economics. The results of the Frontier analysis are only available in summarised form. In particular, wind and solar PV capacity are grouped together as "intermittent renewables". For the purposes of this exercise, it is necessary to determine the split between wind and solar PV as they have different capital costs. MJA's analysis for the Snowy Hydro feasibility study includes an analysis of Renewable projects intended to be developed, which is equivalent to Frontier's "committed" category. The analysis breaks down projects by wind/solar and by state. The total figures differ from the Frontier equivalent by around 1.5 per cent, which is immaterial for the purposes of this exercise:

Table A1 Investment comparison

Frontier Economics	**MW**
Total committed	7,700[2]
of which dispatchable	(2,543) (see below)
Committed intermittent	5,157
MJA[3]	
Wind	3,606
Solar PV	1,625
Committed intermittent	5,231
Difference (MW)	74

[2] ESB, 2017, Executive Summary
[3] MJA, 2018, table 14

Difference (percentage)	1.4%

In order to show *where* investment is projected to occur, it is necessary to make assumptions about the committed dispatchable capacity as set out by Frontier: "2,543 MW of committed investment in dispatchable generation capacity to 2030 under both BAU and the Guarantee, comprising 2,000 MW through Snowy 2.0, a further 338 pumped storage hydro, 198 MW in solar thermal and 7 MW in gas peaking plant."[4]

Snowy 2.0: Allocation 2,000MW NSW. The feasibility study notes that the project will be connected to the NSW transmission network, although output may ultimately flow into Victoria via upgraded interconnection (Snowy Hydro, 2018).

Other pumped hydro: Allocation 338MW Queensland. Of the remainder 338MW pumped hydro, 250MW is the Kidston project in Queensland[5], but it is not obvious what other committed project(s) are represented by the remaining 88MW. Several potential projects in South Australia are being explored but are not committed. There is an existing upgrade project at Snowy's Tumut site, but this is not specifically pumped hydro. So for these purposes, it is assumed to be the Burdekin dam project, also in Queensland[6].

Solar thermal: Allocation 150MW South Australia, 48MW NSW. There is a similar challenge in reconciling the solar thermal figure. 150MW is Solar Reserve's Aurora project in South Australia[7]. There are other possibilities for the remaining 48MW; the most likely appears to be the Jemalong project in NSW, which is already running a pilot plant[8].

Peaking gas: Allocation 7MW South Australia.

The results of this allocation are summarised in the table below. Note that cost figures are national and so the result of the investment calculation in dollar terms is not affected by the jurisdictional allocation.

[4] Op. cit
[5] http://www.genexpower.com.au/the-kidston-pumped-storage-hydro-project-250mw.html
[6] https://www.dews.qld.gov.au/__data/assets/pdf_file/0011/1253828/powering-north-qld-plan.pdf
[7] http://www.solarreserve.com/en/global-projects/csp/aurora
[8] http://www.vastsolar.com/2017/11/28/jemalong-50mw-solar-pv-project-forbes-advocate/

Table A2 Committed dispatchable capacity by state (MW)

Technology type	NSW	QLD	SA	TAS	VIC	NEM
Pumped hydro (Snowy 2.0)	2,000					2,000
Pumped hydro (other)		338				338
Gas peaking			7			7
Solar thermal (6 hrs storage)	48		150			198
Total	2,048	338	157	0	0	2,543

The additional capacity brought on under the National Energy Guarantee is set out in table 3.1 of the Energy Security Board report. This table allocates capacity to the states, but uses fairly broad technology types, and so these capacity figures need to be allocated to more specific technologies .

Gas: 251MW in South Australia allocated to CCGT (described as mid-merit in the report[9]).

Intermittent renewables: 3,271MW across all states. The report indicates this as mostly wind, with around 400MW of large-scale PV[10]. The PV been allocated to Queensland as the most likely location.

Dispatchable renewables and batteries: 836MW in NSW/SA. The report indicates this is expected to be Lithium-ion batteries rather than hydro or solar thermal with storage.

As set out in 3.2 above, the new capacity in the WEM is based on AEMO analysis in the WA ESOO[11]. It is assumed that WA will seek to meet its share of the RET using projects in-state. AEMO provides three potential scenarios. Scenario 1 has been chosen although sensitivity analysis showed that the different in total capacity by MW or dollar value is similar under all three.

The following information is provided about scenario 1 in section 7.2 of the ESOO[12]: WA needs to procure 2,200GWh of additional renewable energy. Scenario 1 assumes that solar PV and wind each provide half of this. AEMO's capacity factors are 34.5% for wind and 24.3% for solar. The total new

[9] Energy Security Board Advice to the Commonwealth Government on the National Energy Guarantee p17
[10] Ibid, p18
[11] AEMO 2017 WEM Statement of Opportunities
[12] Ibid, pp65-66

capacity is 895MW, qualifying for 296MW of capacity credits. From this data, it can be algebraically derived that the capacity split is 370MW wind, 575MW solar.

The ESOO forecasts demand out to 2026/27. Using the average growth rate in peak demand of 1.7% pa allows demand to be extended to 2030. The same factor is applied to the reserve margin (since it is calculated by reference to peak demand) while intermittent loads and load-following requirements are held constant (as they are throughout the ESOO forecast period).

Table A3 WEM demand forecasts (MW)

	2026-27[13]	**2029-30**
Peak demand	4,799	5,048
Intermittent loads	4	4
Reserve margin	365	384
Load following	72	72
Total	5,240	5,508

The ESOO expects existing generation to deliver 4,807MW of capacity credits[14], so 701MW must be provided by new capacity. If 296MW is provided by the RET investments described above, then a further 405MW will be required. The cheapest way to deliver this capacity over that time frame is gas peaking plant.

The results of these calculations are shown in Table A4 below (it is shown graphically in Figure 3: New capacity by state (MW) above)

[13] Ibid, p57 – table 19
[14] Ibid, p61

Table A4 New capacity by state (MW)

	NSW	QLD	SA	TAS	VIC	WA	Total
Pumped Hydro	2,000	338	-	-	-	-	2,338
Natural gas	-	-	258	-	-	405	663
Wind	1,937	1,156	889	771	1,723	370	6,846
Large scale solar PV	201	1,484	320	-	20	525	2,550
Solar thermal with storage	48	-	150	-	-	-	198
Battery storage	521	-	315	-	-	-	836
Total	4,707	2,978	1,932	771	1,743	1,300	13,431

The Author

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In his role as head of networks financial issues at Ofgem, he specialized in issues such as cost of capital, tax pensions and financial modelling as well as incentive design for gas and electricity networks. He developed the first Return on Regulatory Equity calculation and also the annual price control reporting process for gas distribution. This involved the introduction of standardised annual reporting of cost, revenue and quality of service information, including data that could be used to derive consistent profitability measures of the sort discussed in this report.

Kieran holds Masters degrees from the Universities of Oxford and London.

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