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# GenCost 2018

## Updated projections of electricity generation technology costs

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December 2018

## Citation

Graham, P.W., Hayward, J, Foster, J., Story, O.[1] and Havas, L. 2018, *GenCost 2018*. CSIRO, Australia.



## Erratum

Copies of this report downloaded from the CSIRO publications repository before 19 February 2019 contained an error in the wind and solar photovoltaic with storage cost ranges of Figure 4.2 through to 4.5. No other figures or data tables were impacted.

[1] Oliver Story is Director Strategy at ARENA and co-authored Focus Area B: Extending GenCost to include demand management. The remaining authors are all CSIRO officers.

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# Acknowledgments

This report benefited from the input of stakeholders at various briefings and workshops in the second half of 2018 and from the GenCost project working group consisting of Ross Lambie, Dane Winch, Nicola Falcon and Oliver Story. However all errors and omissions remain the responsibility of the authors.

# Executive summary

Electricity market modelling for the exploration of alternative energy futures remain an important part of strategy planning for government, institutions and industry. Regularly updated current and projected electricity generation and storage technology cost information remains a necessary and highly impactful input into electricity market modelling studies. Furthermore, there are substantial coordination benefits if all parties are using similar cost data sets for these activities or at least have a common reference point for differences.

This GenCost project is the result of a collaboration between CSIRO and AEMO, together with stakeholder input, to deliver an annual process of updating electricity generation costs. CSIRO and AEMO have both committed their own resources to deliver the project with the aim of increasing the likelihood of delivering the continuity that was not achieved in predecessor studies. Wide stakeholder engagement and transparency are also built into the project design. The main workshops and other engagement supporting this activity were held in August through November 2018.

The projection methodology is grounded in a global electricity generation and capital cost projection model recognising that cost reductions experienced in Australia are largely a function of global technology deployment. The updated projections indicate that solar photovoltaic (PV) capital costs continue to fall at a faster rate than most other technologies and solar PV is projected to represent one of the largest contributors to electricity generation by 2050. Wind, batteries, pumped hydro and CCS are also expected to feature more strongly in the global electricity generation mix and consequently achieve cost reduction through increased deployment. Pumped hydro and compressed air storage are new inclusions in the technology set compared to previous equivalent studies and highlight the expected increasing role for storage in the electricity system.

While the capital cost projections are primarily designed to be included in Australian electricity modelling studies as scenario inputs we recognise that some stakeholders require access to levelised cost of electricity (LCOE) data for comparing technologies outside of models. On the other hand LCOE estimates, in their current form, can be misleading if they apply the same discount rate regardless of exposure to climate policy risk and inherently do not recognise the additional balancing technology that is required by variable renewable generation as its share of the generation mix increases. Given the variable renewable share is expected to increase in most Australian states, towards or beyond 50%, this is an issue that needs to be solved. This report provides some advice on what comparisons are and are not appropriate using current methods and describes a process by which future updates will seek to solve this issue with new approaches.

Finally, like storage, demand management is another resource which we expect the electricity sector will need to draw on more deeply in coming years to assist in balancing the system and reducing system costs. However, demand management costs and the scale of their potential contribution varies widely depending on the customer and timeframe. We find that a significant amount of data related to demand management costs is already available, but its ongoing collection can be costly so the next step is to prioritise the most attractive demand management resources to monitor.

# 1 Introduction

## 1.1 The need for an annual cost update process

Current and projected electricity generation and storage technology costs are a necessary and highly impactful input into electricity market modelling studies. Modelling studies are conducted by the Australian Electricity Market Operator (AEMO) for planning and forecasting purposes. They are also widely used by electricity market actors to support the case for investment in new projects. Governments and regulators require modelling studies to assess alternative policies and regulations. There are substantial coordination benefits if all parties are using similar cost data set for these activities or at least have a common reference point for differences.

### 1.1.1 Predecessor studies

The EPRI (2010) technology cost assessment was the first major attempt to create a public cost data source that could be used by all electricity industry stakeholders. Its major flaw was a lack of adequate stakeholder engagement and transparency of methods, particularly in regard to emerging renewable electricity generation costs.

Starting from 2012, the Bureau of Resource and Energy Economics (BREE) sought to establish an annual process with a strong emphasis on transparency of calculations and included the necessary engagement processes to ensure the outputs would be more broadly accepted. The BREE (2012) *Australian Energy Technology Assessment* (AETA) was not able to be sustained beyond the BREE (2013) update. However, the CO2CRC (2015) provided another update, the *Australian Power Generation Technology* (APGT) report, using the process established by BREE. This was well received but did not allow for future updates.

CSIRO participated in the 2012, 2013 and 2015 studies, being responsible for developing the projected changes in capital costs over time using its Global and Local Learning Model (GALLM), which was developed in 2011.

Currently, given the rapid change in the costs of some technologies, the APGT 2015 study is considered substantially out of date and as a result modelling studies today are using a variety of updates generated by a variety of sources. CSIRO conducted its own update on the APGT 2015 study, but without the collaboration and engagement that was a feature of previous work (Hayward and Graham, 2017).

Overall, while there have been some high quality processes in the past, these efforts have failed to sustain an annual process for updating electricity generation technology costs. Annual updates are essential when technology costs are changing rapidly.

## 1.2 Scope of the GenCost project and reporting

The GenCost project is a joint initiative of CSIRO and AEMO to provide an annual process for updating electricity generation cost data for Australia. The goal is to adopt the best features of predecessor processes and deliver the required data in a more modest format, but one that allows for incremental improvement over time. The key elements the project adopts from previous work is a commitment to stakeholder engagement and transparency. Continuity is also maintained by applying CSIRO's model (GALLM) for projecting changes in costs.

Some key differences are that the main output (this report) will not seek to describe the technologies in detail (which was a feature of previous approaches), will be updated annually and will be more flexible about including new technologies of interest or not updating information about some technologies where there is no reason to expect any change or their applicability is limited.

### 1.2.1 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own in-kind resources. The governance process includes a Reference group consisting of members from CSIRO, AEMO, ARENA, DEE and DIIS. The Reference group has three primary roles:

- Advise on the initial design of GenCost
- Advise on the forward plan to deliver continuous incremental improvement in methods and identify items to add or remove from the scope
- Review project delivery and activities to ensure GenCost processes and outputs are open and unbiased

AEMO commissioned GHD to provide an update of current electricity generation cost and performance characteristics for current and new electricity generation (GHD, 2018). These were used as a starting point for discussions with a wide range of stakeholders including workshops and briefings in the second half of 2018. The final estimates are presented in Section 2. Project management, workshops, capital cost projections (presented in Section 3) and this final report are primarily the responsibility of CSIRO.

### 1.2.2 AEMO's intended use

AEMO intends to use the data and information provided in this GenCost report as the basis for broader consultation on inputs and assumptions to be used in key forecasting and planning publications such as the Integrated System Plan (ISP). While AEMO and CSIRO have endeavoured to capture stakeholder feedback during the course of this study, it is recognised that the assumptions are made at a point in time and the market is evolving rapidly. Therefore, AEMO is open to further modifying these assumptions if new material data and information comes to light through the ISP consultation process. This information would then inform subsequent GenCost reports. The consultation for 2019 is planned to be initiated in the next month.

### 1.2.3 Incremental improvement and focus areas

There are a large number of assumptions, scope and methodological considerations underlying electricity generation technology cost data. In any given year we are readily able to change assumptions in response to stakeholder input. However, the scope and methods may take more time to change and input of this nature may only be addressed incrementally over several years, depending on the priority (as discussed, input may be sought from the Reference group to prioritise changes).

For GenCost 2018 we prioritised two focus areas for improvement:

- Extension of Levelised Costs of Electricity (LCOE) estimates
- Extending GenCost to include the cost of demand management

In both cases, the objective was to review a potential way forward for incorporating new approaches into the GenCost project. The findings of those reviews is discussed in sections 4 and 5. The latter focus area was co-authored with the Australian Renewable Energy Agency (ARENA).

CSIRO also delivered some improvements in its cost projection methodology which are discussed in Appendix A. Appendix B provides data tables for those projections.

# 2 Current technology costs and performance

AEMO commissioned GHD (2018) to provide an update of current electricity generation technology cost and performance data for existing and selected new electricity generation and storage technologies. This data is used in this report as the starting point for projections of capital costs to 2050 and for calculations of the levelised cost of electricity. The GHD methodology used a combination of specific electricity generation cost estimation software tools together with their own knowledge of typical projects.

The capital costs are overnight costs for construction in Melbourne which is used as the reference for regional costs adjustment factors which are provided to calculate costs elsewhere in Australia.

Compared to previous studies, the GHD (2018) technology list has changed slightly. Integrated gasification combined cycle coal plant are not included due to a lack of commercial interest. Battery storage, pumped hydro energy storage (PHES) and compressed air storage has been included. Also where previous studies focussed on large scale nuclear (a GW or more), only small modular reactor (SMR) nuclear electricity generation is included. This is appropriate given smaller plant are more likely to proceed in Australia.

Feedback from stakeholders suggested that large plant of any kind (nuclear, coal and gas) will be more difficult to deploy because of falling minimum demand and the greater redundancy required to cover an unplanned outage of a large plant. Future GenCost updates will likely focus on smaller plant.

## 2.1 Generation technology capital costs 2018

Figure 2-1 provides a comparison of the GHD (2018) current cost estimates for electricity generation technologies with two previous reports: Hayward and Graham (2017) (CSIRO) and CO2CRC (2015) which we refer to as APGT (short for *Australian Power Generation Technology* report). All costs are expressed in real 2018-19 Australian dollars. CSIRO's estimate for 2018 rooftop solar PV cost is included in the GHD/CSIRO data as that technology was not part of GHD (2018). Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme[2]. For the coal technologies, each study provides a wide range of technology types (e.g. super critical, ultra-supercritical). We have only included the lowest capital cost variation.

Given each study was delivered by separate authors and not all data inputs and working are published, it is generally not possible to explain differences between alternative estimates. However there are a few broad trends. The first is that projected 2018 costs of solar PV (rooftop and large scale) and wind were overly conservative in APGT and again, for large scale solar PV in CSIRO (2017). The second is that we still have considerable uncertainty around estimating costs for technologies which are not currently being built in Australia. In particular, costs for solar thermal

[2] See http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works/Small-scale-Renewable-Energy-Scheme

(with 8 hours storage) and carbon capture and storage (CCS) technologies combined with brown coal, black coal or natural gas continue to vary significantly between studies.

For solar thermal, the CSIRO (2017) value was based on applying the expected value of the announced Aurora project in South Australia to be delivered in 2020. This approach was not repeated, with GHD (2018) using the results from the System Advisor Model[3]. However, in the next section, we find that using the GHD (2018) starting value, the projections for the year 2020 remain consistent announced Aurora project costs. That is, our global projection modelling finds global solar thermal deployment will drive solar thermal cost reductions over the next two years consistent with the Australian project. For CCS, the differences in assumptions are not as clear and there are currently no new Australian projects with which to cross-check model derived numbers.

Changes in CSIRO's estimates of rooftop solar PV costs between 2017 and 2018 are mostly as a result of a change in methodology for choosing a representative rooftop solar system size rather than representing a view that rooftop solar PV is higher in cost. Such data is available from a variety of online sources[4]. There are economies of scale in rooftop solar PV systems which means that larger system sizes are lower cost in $/kW.

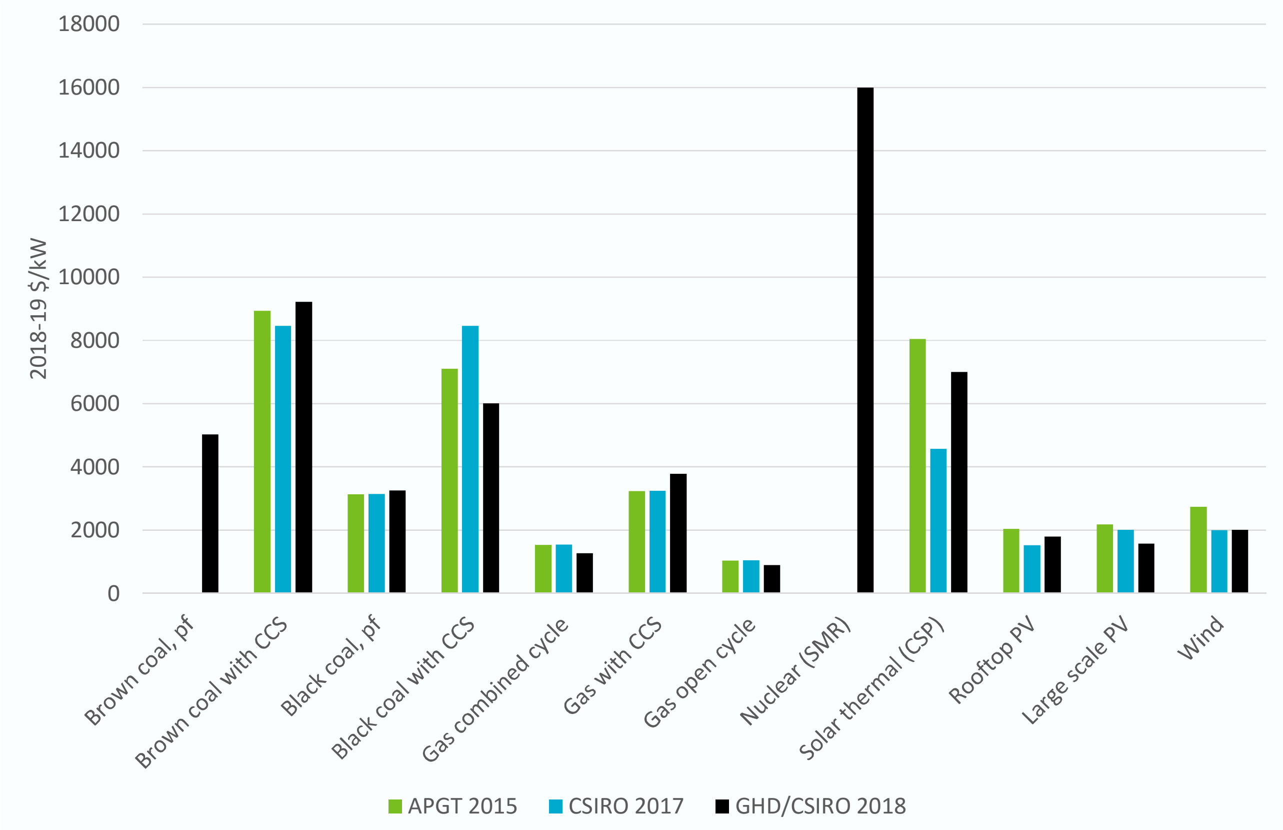


**Figure 2-1: Comparison of 2018 capital costs of generation technologies with estimates from previous studies**

[3] See https://sam.nrel.gov/

[4] See https://www.solarchoice.net.au/blog/solar-power-system-prices for example.

## 2.2 Storage technology capital costs 2018

The current cost of storage from GHD (2018), CSIRO (2017), Entura (2018) and Blakers et al. (2017) are shown in Figure 2-2 and Figure 2-3 and tabled in Appendix B. The Blakers at al. (2017) study is not a 2018 cost estimate but near enough for our purpose given the lack of other comparable data available. Storage capital costs can be presented as separate component costs (for power ($/kW) and energy ($/kWh) which must be multiplied by the power and energy capacity of a project and added together (Figure 2-2). Alternatively they can be presented as a total cost where either the power or energy capacity has been divided through the total project value (Figure 2-3). For example, a storage project that costs $40m and has a power capacity of 20MW and energy capacity of 40MWh. The cost for this project can then be expressed as either $2000/kW or $1000/kWh on a total cost basis.

GHD (2018) provide component costs for battery and compressed air storage projects. These costs are used to calculate total costs for a 1 hour storage per power capacity battery project and a 48 hours per power capacity compressed air project. To compare with other studies we convert these component costs to total project costs at the power to energy storage ratios provided.

For battery storage, the CSIRO (2017) cost estimate was for a project with 2 hours of storage per power capacity. Therefore, to make the comparison we include the GHD (2018) project but also add a "GHD modified" project with 2 hours storage per power capacity which uses the component costs[5] to create a project with the same power to energy ratio as CSIRO (2017). The CSIRO and GHD modified 2 hours storage project cost are fairly well aligned. One source of uncertainty is that costs for battery project will vary between projects depending on whether they are co-located with a renewable energy generation project or not. The CSIRO value assumed co-location and includes some savings relative to a standalone project, but GHD does not.

[5] The total cost basis estimate included land and other costs from GHD (2018), assuming they are same as a 1 hour project

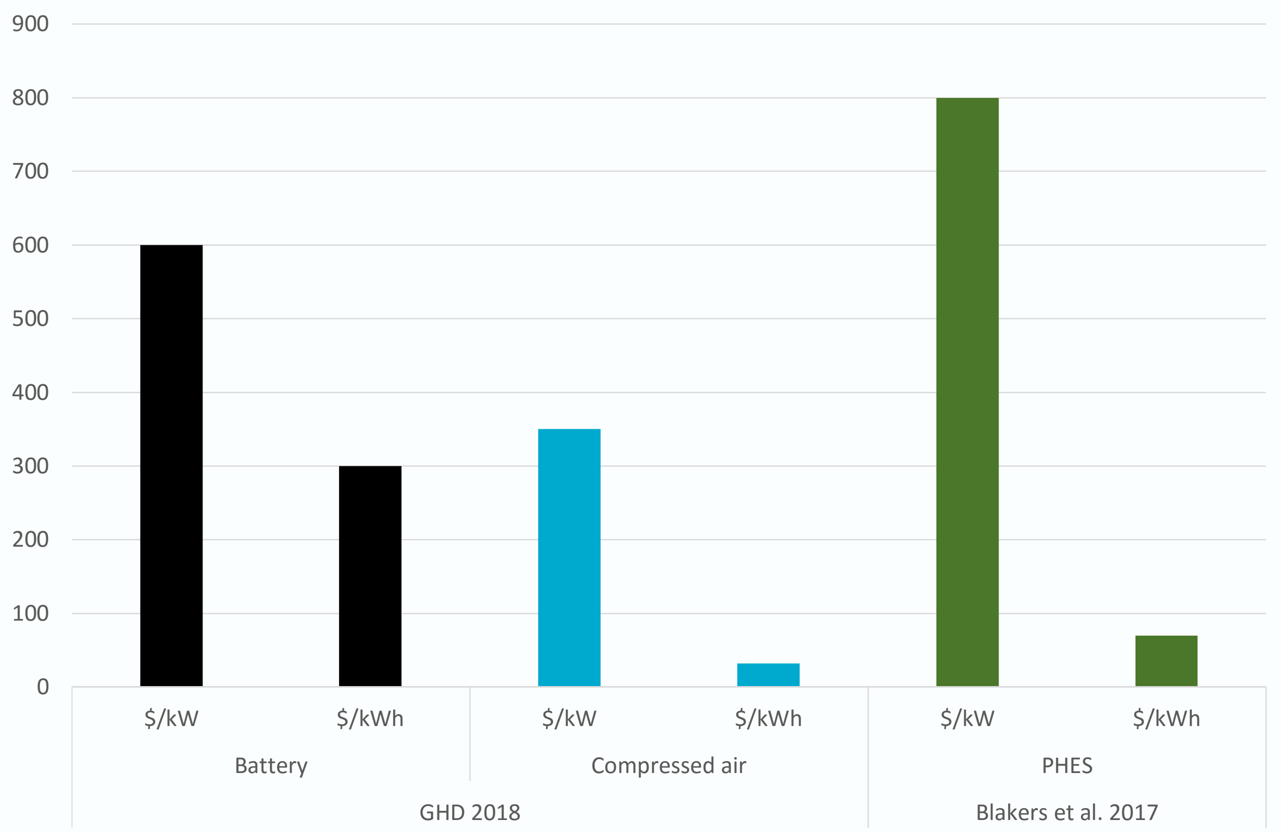


**Figure 2-2: Component costs basis comparison of capital costs of storage technologies**

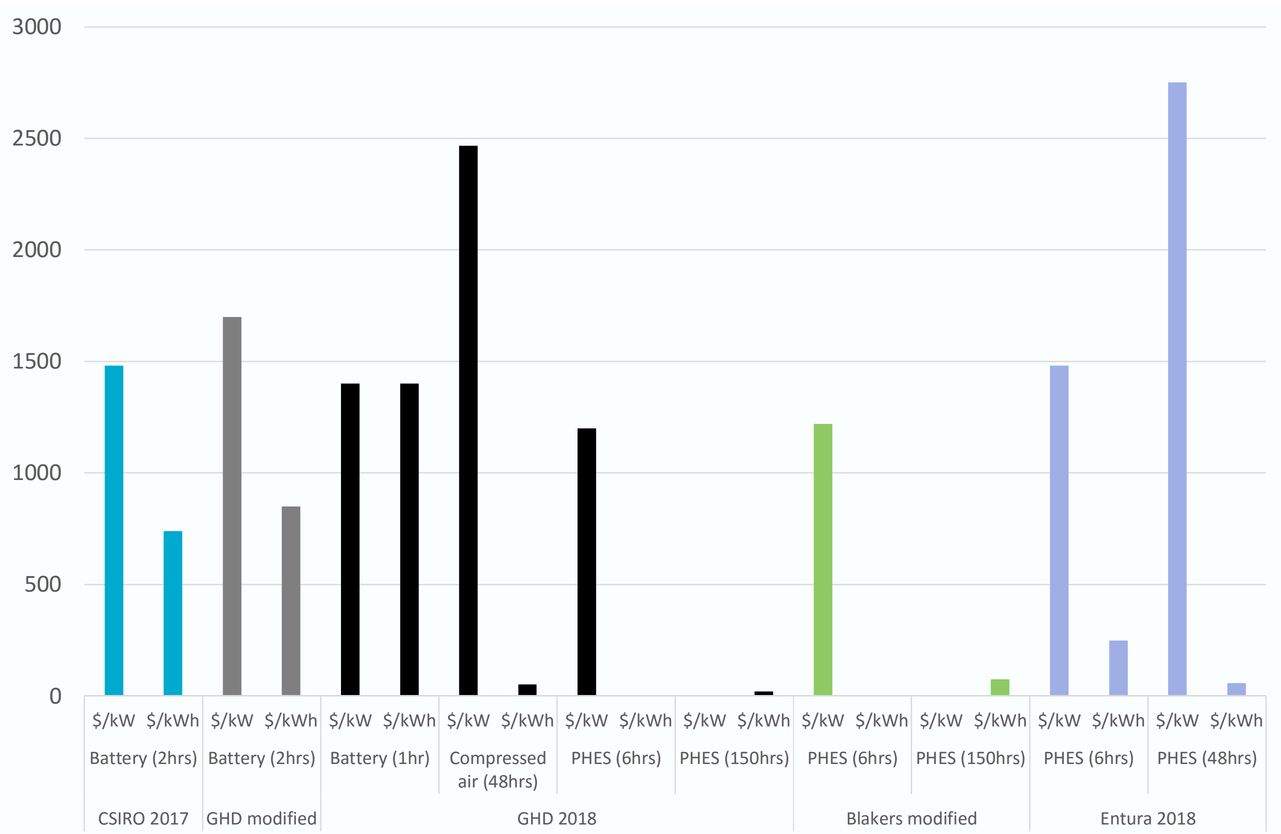


**Figure 2-3: Total cost basis comparison of capital costs of storage technologies**

For compressed air storage, we do not have a previous study for comparison. However, we can note that the total costs in $/kWh terms are similar to other longer period energy storage technologies, and so it would appear to be competitive in this niche.

For PHES, we have included the Blakers et al. (2017) component costs as a point of comparison and also converted them to a total cost basis since GHD (2018) only report PHES in these terms using two project sizes 6 hours and 150 hours storage per power capacity (we call these “Blakers modified”). The GHD (2018) and Blakers modified estimates for PHES are almost identical for a 6 hours storage per power capacity project (in $/kW). The Entura (2018) cost for PHES with 6 hours storage is a little higher. Entura (2018) costs are an average across the top 25% of projects in the NEM.

The GHD (2018) costs for the 150 hours storage per power capacity project is significantly lower than the Blakers modified estimate. Unlike battery storage which is modular and somewhat indifferent to the project site, differences in estimates of PHES project costs should not be surprising. There are a number of local project site assumptions that impact PHES costs. Entura (2018) did not include a 150 hour storage PHES project. However, its 48 hour storage project cost (again based on an average of top 25% of projects) sits around midway between the Blakers modified and GHD estimates for 150 hours.

# 3 Capital cost projections

## 3.1 Scenarios

Given our capital cost projections are a function of global and local technology deployment, it is important to set a global context. The key contextual factors which we have chosen to set are the global climate change goal, electricity demand and fuel prices. We apply two scenarios called 4 degrees and 2 degrees which describe the global climate policy goal. The goal is implemented in the model via carbon prices which are sourced from Clarke et al. (2014) and are shown in Appendix A. The carbon prices only provide a reasonable chance of meeting those climate policies goals, not a guarantee. Global electricity demand and fossil fuel prices are assumed to be consistent with the IEA (2017) Sustainable development (assigned to 2 degrees) and New policies (assigned to 4 degrees) scenarios. New policies includes policy already in place and declared policy intentions including actions consistent with the Paris Agreement Nationally determined Contributions. Sustainable development puts the world on a pathway that would be consistent with limiting temperature increase to less than 2$^{o}$C as well as reducing local air pollution and broadening access to affordable energy.

These scenarios are used to develop alternate cost projections from a global perspective, and may help set the global scenario narrative for AEMO forecasting and planning scenarios, but are not directly linked. For example, any Australian climate change and energy policy assumed in AEMO's scenarios will be determined through consultation and in the context of existing federal and state policies, not these global carbon price assumptions. Other assumptions such as learning rates and some technology assumptions do not vary by scenario and are discussed in Appendix A.

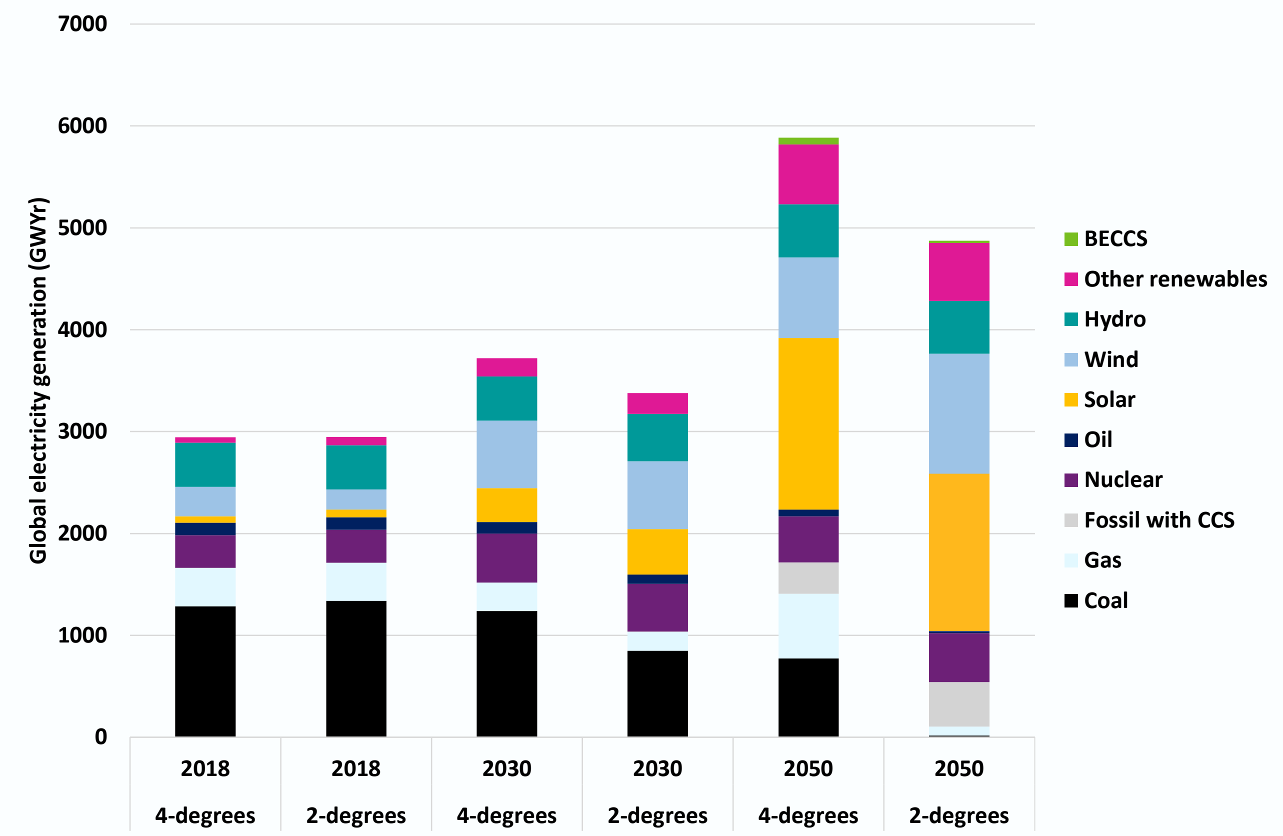


**Figure 3-1: Projected global electricity generation mix under the 4 degrees and 2 degrees scenarios**

The projected outcome for the global electricity generation technology mix (which is simultaneously solved together with the cost projections) is shown in Figure 3-1. The scale of generation reflects the input assumptions for each scenario with 2 degrees electricity demand growth assumed to be lower, presumably reflecting a decrease in electricity intensity of the global economy (even in spite of an expected electrification of global road transport). In terms of the generation mix, the 2 degrees scenario has the least fossil fuel generation by 2050 reflecting a higher carbon price. CCS technology adoption is higher and so is wind. However, the scale of deployment of solar, BECCS and other renewables is slightly higher under 4 degrees. This is because the scale of electricity demand remains high and so in spite of lower carbon prices the scale of deployment of some low emissions technologies is higher. Accordingly, neither 4 degrees nor 2 degrees is substantially better for deployment of low emissions technologies, with the exception of fossil CCS.

The generation mix does not show storage charging and discharging to balance the system. Our projection approach currently includes battery and pumped hydro energy storage. Hourly modelling is conducted to calculate how much storage is required and this modelling also informs the mix of renewables in each region since applying non-coincident variable renewables is one of several ways of balancing the outputs from variable renewables. Figure 3-2 provides an example of outputs from the hourly modelling from three days in spring. This example, from the North American region, indicates that battery storage is providing the main task of system balancing, charging up on solar and wind outputs and discharging in the evening.

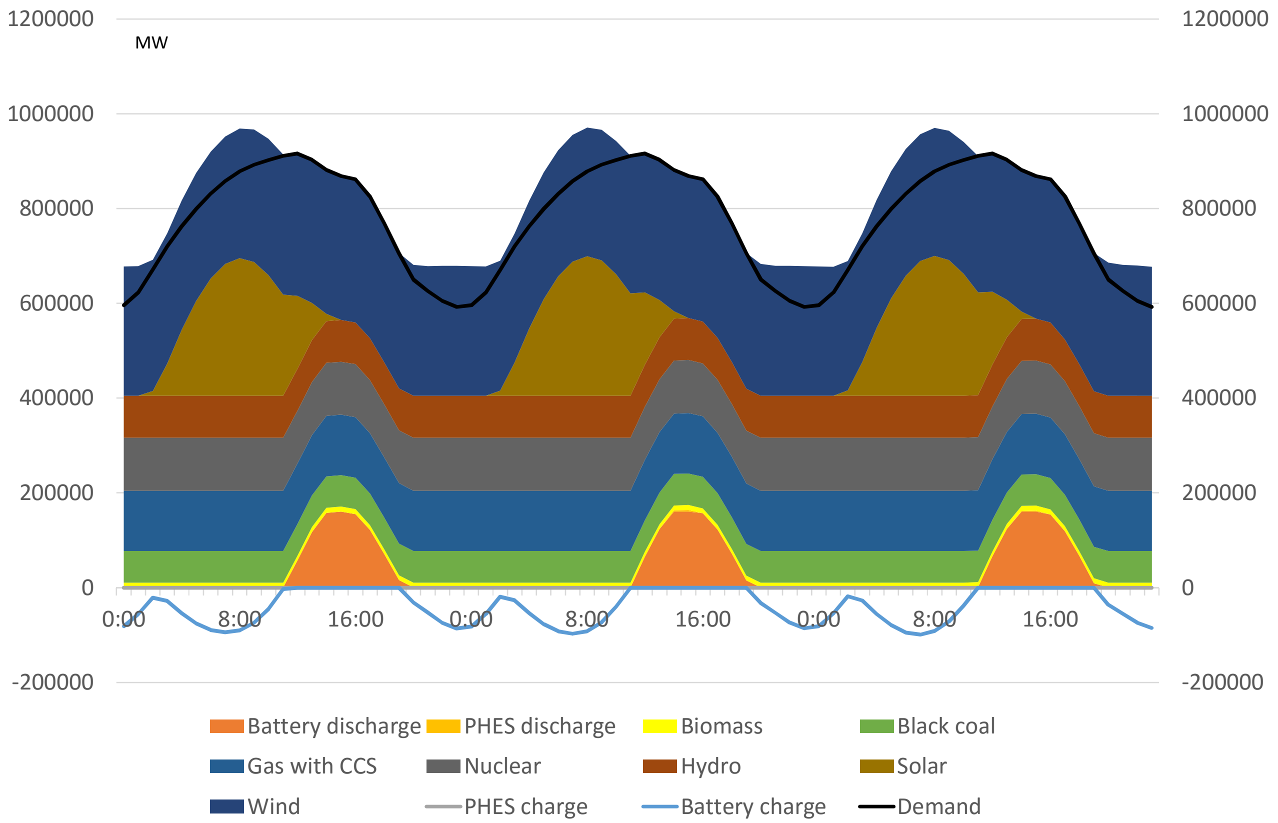


**Figure 3-2: Example output from hourly modelling**

## 3.2 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to previous work. Comparable data from previous studies are only available for the main technologies. The projections are compared to CSIRO (2017) which used the same scenarios and is shown in blue. Shown in green, is the CO2CRC (2015) which applied scenarios based on greenhouse gas atmospheric concentrations but these remain broadly comparable with the equivalent temperature targeting scenarios used here. Note that GALLM was the projection model in all three cases although there have been changes in both model structure and assumptions in each study.

Since CO2CRC (2015) and CSIRO (2017) use the same model, similar scenarios and in some cases a common starting point, their projection pathways often overlap. Besides an updated starting point, the 2018 data also used a different assumed annual rate of cost reduction for mature technologies of -0.012% compared to -0.5% in previous studies. The method for calculating the updated reduction rate for mature technologies is outlined in Appendix A.

Data tables for the full range of technology projections are provided in Appendix B.

### 3.2.1 Black coal supercritical

Given its maturity, black coal supercritical generation technology is not subject to any assumed learning rate. Instead mature technologies are assigned an annual cost improvement rate based on extrapolated trends of a bundle of material and labour costs which is described further in Appendix A. The difference between the projections in Figure 3-3 is as result of the revised current cost estimate from GHD (2018) being slightly higher and a revision to annual cost improvement rate assumption. The revised assumption applied in 2018 is for a slower rate of annual improvement for mature technologies and it does not vary across scenarios.

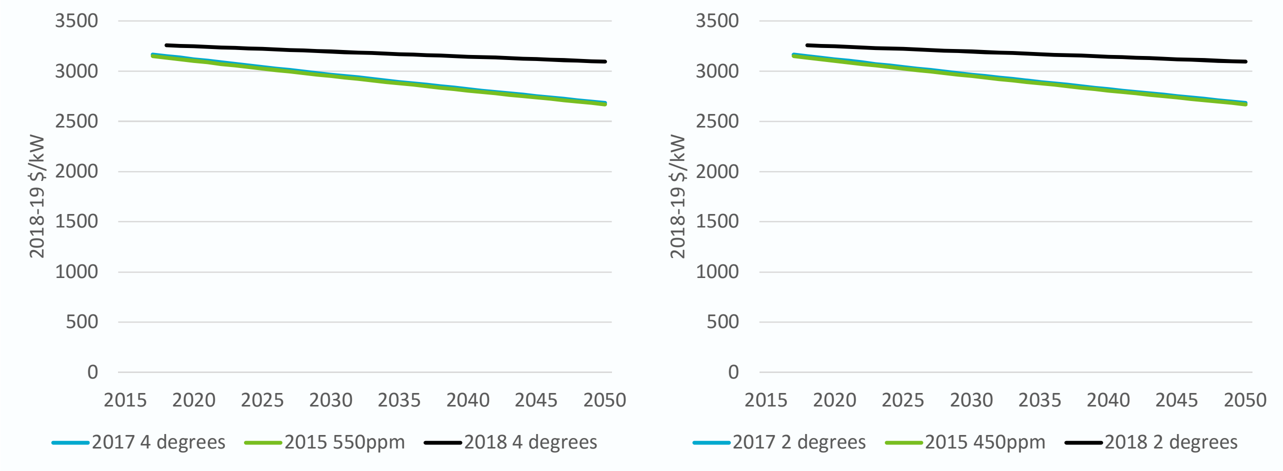


**Figure 3-3: Projected capital costs for black coal supercritical compared to two previous studies**

### 3.2.2 Black coal with CCS

Figure 3-4 shows the projected capital cost for black coal with CCS (whatever is the prevailing cheapest technology[6]) compared to the selected previous studies. The mature component of black coal with CCS (i.e. the pulverised fuel steam plant) is impacted by a slower annual cost improvement rate, like black coal supercritical generation. The CCS component is subject to learning and can achieve cost reduction from other non-black coal deployment of CCS (i.e. in natural gas or brown coal CCS). Significant global CCS deployment begins around the late 2030s under the 4 degrees scenario and late 2020s under the 2 degrees scenario. The timing for CCS deployment is generally later in the 2018 projections (although in the 2017 projections CCS was not deployed at all in the 4 degrees scenario).

Local learning in relation to installation is also included if a country directly deploys CCS. Across both scenarios, the starting cost for black coal with CCS is lower based on GHD (2018). As a result, despite slower annual improvements in the mature component, the level of costs in 2050 are similar to the 2015 projection.

[6] In this case, the cost relates to advanced ultra supercritical black coal from the GHD (218) report

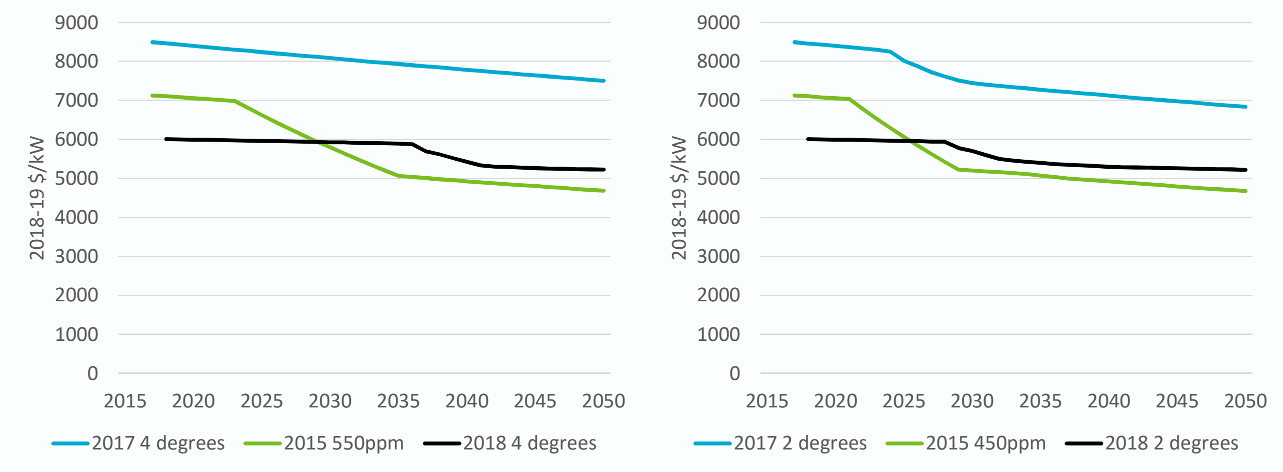


**Figure 3-4: Projected capital costs for black coal CCS compared to two previous studies**

### 3.2.3 Brown coal with CCS

Similar to black coal, the brown coal CSS projections represent a generic label of best available technology type[7]. The technology is made up of mature elements which receive an annual improvement rate and CCS elements which are eligible for co-learning with all global fossil with CCS deployment. Local learning in relation to installation is also included.

Global deployment of fossil with CCS technology in the late 2020s (2 degrees) and late 2030s (4 degrees) reduces brown coal with CCS costs in addition to improvements in mature technology cost components (Figure 3-5). While the starting level of brown coal with CCS costs is slightly higher in the 2018 projections, by 2050, in the 2 degrees scenario the gap has continued to widen. The gap only closes with the 2017 4 degrees scenario because those projections did not include any deployment of CCS.

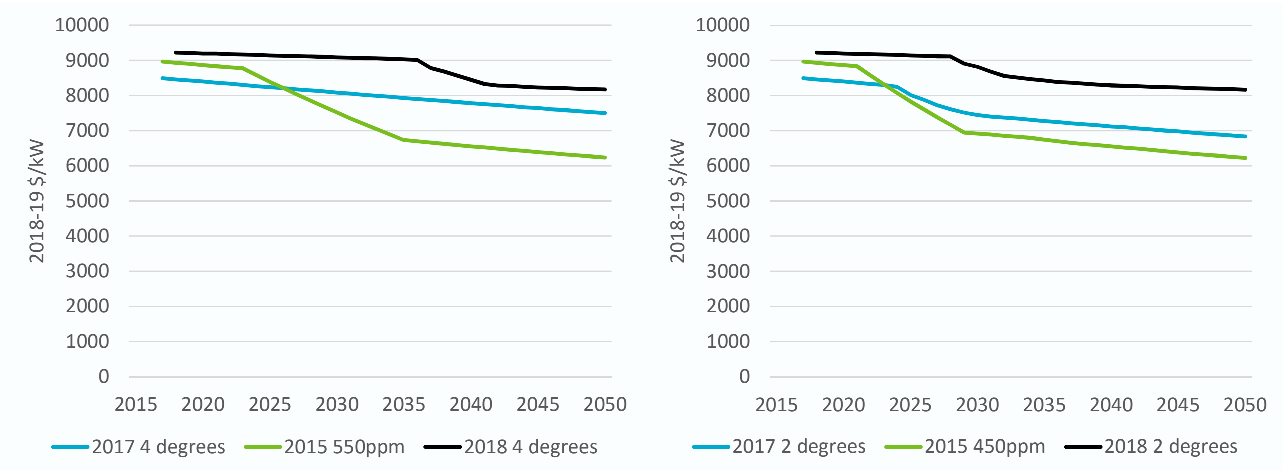


**Figure 3-5: Projected capital costs for brown coal CCS compared to two previous studies**

[7] In this case GHD (2018) has provided costs for a supercritical brown coal plant with CCS.

### 3.2.4 Gas combined cycle

Gas combined cycle is a mature technology and the cost trajectory is a function of an assumed annual improvement rate. This was a change in methodology from the two previous studies which employed a small learning rate for this technology rather than an automatic annual cost reduction. However, it appears in this case either methodology arrives at a similar conclusion that costs for this technology will be relatively stable to 2050 (Figure 3-6). The major difference between the projections is the starting point with GHD (2018) providing a lower starting point for the 2018 projections.

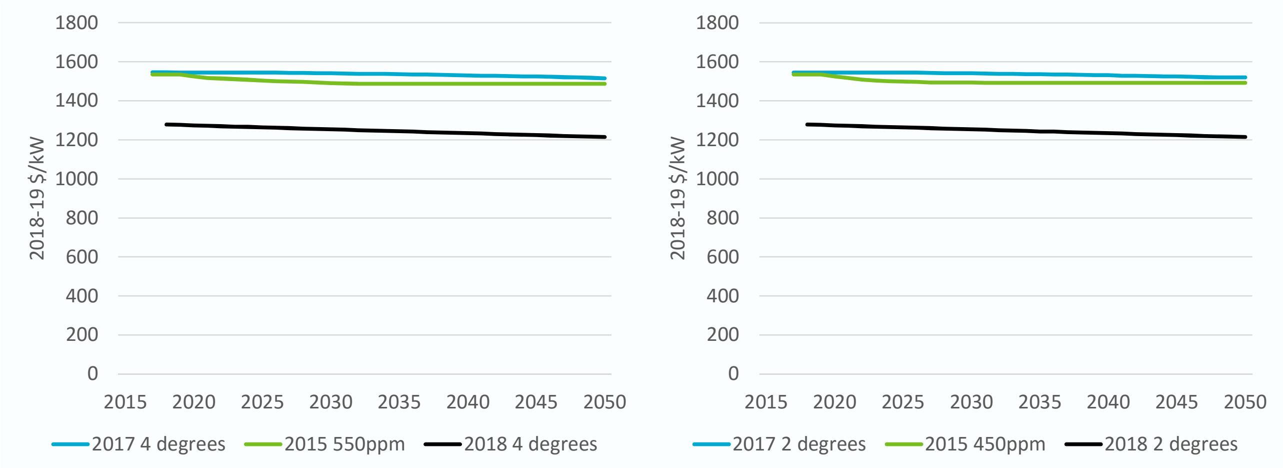


**Figure 3-6: Projected capital costs for gas combined cycle compared to two previous studies**

### 3.2.5 Gas with CCS

Compared to the brown and black coal technologies, the CCS component, which is subject to a learning rate with each doubling of capacity deployed, is a larger proportion of the overall capital cost of gas with CCS. The mature component (the combined cycle turbine) is smaller and only improves at the common annual improvement rate for all mature technologies. Due to the larger CCS component, while gas shares the same learning with all fossil with CCS technologies, the impact of improvements in CCS is proportionally greater for gas with CCS.

In the 2 degrees scenario we can see in Figure 3-7 that the 2018 projected level of cost reduction is very similar to 2017, but is delayed by around 7 years. The projected cost reduction is about half the scale of projected cost reductions in 2015. This is because fossil with CCS is projected to be a smaller component of the global electricity generation mix owing to greater cost reductions from renewables (since the 2015 study).

GHD (2018) have provided a higher starting value for gas with CCS. As a result, the 2018 projections remain above the previous studies except for the last decade in the 4 degrees scenario which is below 2017 projections owing to the 2017 projections not finding any CCS deployment.

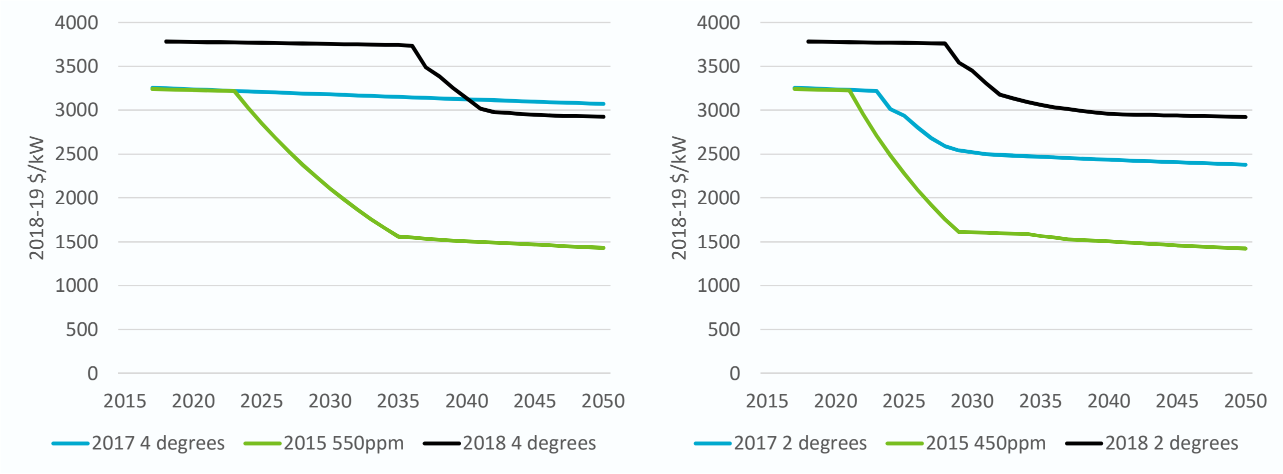


**Figure 3-7: Projected capital costs for gas with CCS compared to two previous studies**

### 3.2.6 Gas open cycle

Gas open cycle is included as a mature technology in the projection model and as a consequence has an assumed annual cost reduction rate. The assumed rate has changed since the two previous studies in 2015 and 2017 which accounts for the differences in the rate of reduction shown in Figure 3-8. The other major difference in the projections is the starting point which is lower in the 2018 projections following GHD (2018). The GHD (2018) cost relates to a 550 MW unit. Were a smaller unit assumed then the starting cost may be higher and therefore closer to previous work[8].

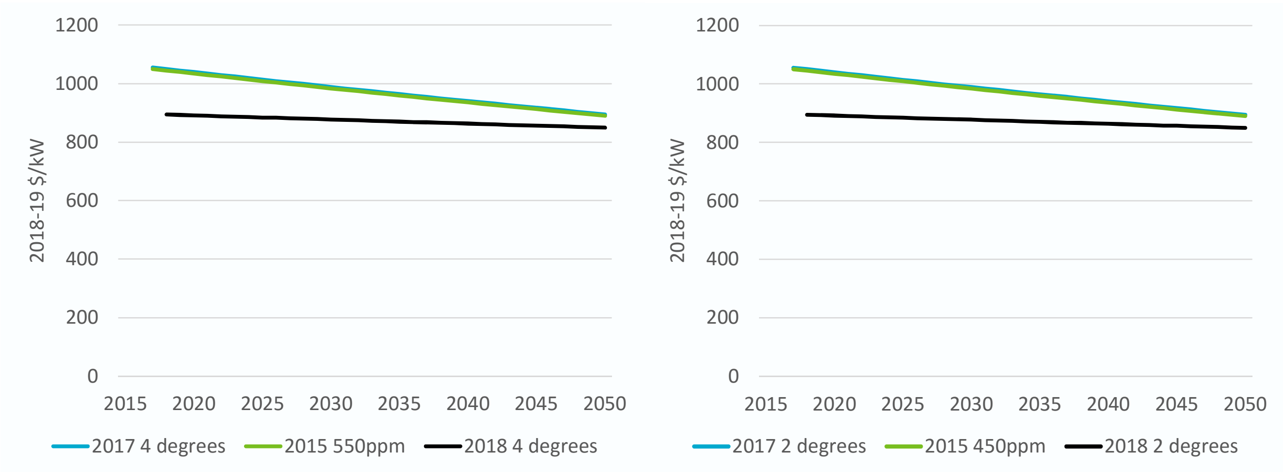


**Figure 3-8: Projected capital costs for gas open cycle compared to two previous studies**

### 3.2.7 Nuclear

The nuclear generation technology capital cost projections shown in Figure 3-9 are not comparable because the 2018 projections relate to small scale modular reactors, while the projections in 2015 and 2017 are for large scale nuclear. However, we make the comparison to

[8] As an indicator, Lovegrove et al. (2018a) apply a power function to adjust for scale in their work. Project cost is typically estimated as a function of plant size to the power of 0.7. Applying this approach would increase gas open cycle costs, from $894/kW for a 550MW plant, to $1211/kW for a 200MW plant.

indicate that they share a common flat trajectory. The flat trend arises because, while nuclear is assigned a learning rate to recognise the potential for further improvements in the technology, they do not experience significant changes in costs due to the limited scope to double global cumulative capacity. In this sense, nuclear power is caught between having the existing deployment scale of a mature technology, but with the technological potential of an immature technology in terms of optimal technology design not being completely settled. Another factor which partially constrains nuclear deployment is that, besides economic drivers, its uptake is significantly influenced by government policy. We have included where possible our understanding of the current stance of governments in relation to nuclear generation technology in each region in our projection model.

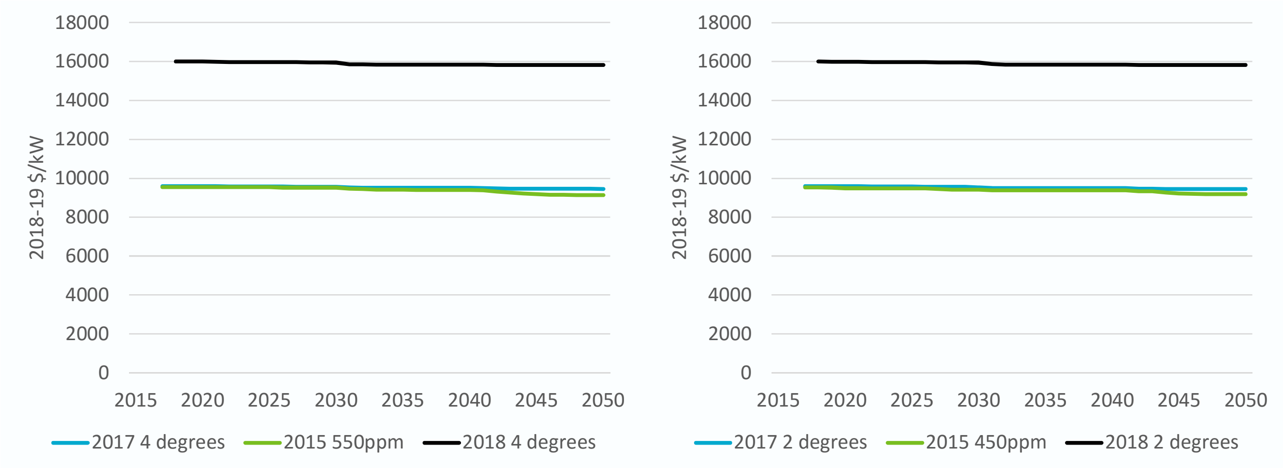


**Figure 3-9: Projected capital costs for small (2018 projections) and large scale nuclear from 2015 and 2017 projections**

### 3.2.8 Solar thermal (CSP) with 8 hours storage

The solar thermal technology included in the projection model is a generic label representing best technology and that tends to be concentrating solar power with storage. As discussed in Section 2, the 2017 projections had previously assigned the planned South Australian Aurora project costs as the starting value for projections. However, in the 2018 projections the starting value has been assigned using the higher GHD (2018) value based on modelling. However, by 2020, when the South Australia project is due for completion the projected cost reductions are aligned with that project (Figure 3-10).

Both the 2017 and 2018 projections imply a period of significant learning through deployment in the next 2 years for solar thermal. However, during the 2020s and early 2030s deployment is projected to stall. This is not surprising since the solar thermal technology we have included in the projection modelling includes 8 hours storage. Analysis by Campey et al. (2017) has found that 8 hours storage is not required to support variable renewables until very high variable renewable shares are reached, which is in the latter half of the projection period for most regions. The current configuration of our global technology cost projection model does not include solar thermal with less than 8 hours storage. The absence of these options may be responsible for this delayed deployment in solar thermal. Potentially, if we were to consider 2 and 4 hours storage variations we would see these technologies deployed sooner, ameliorating the flat trend in the 2020s and 2030s.

Solar thermal is deployed slightly earlier and to a greater extent in the 4 degrees scenario leading to lower costs. This reflects the higher electricity demand assumed under 4 degrees.

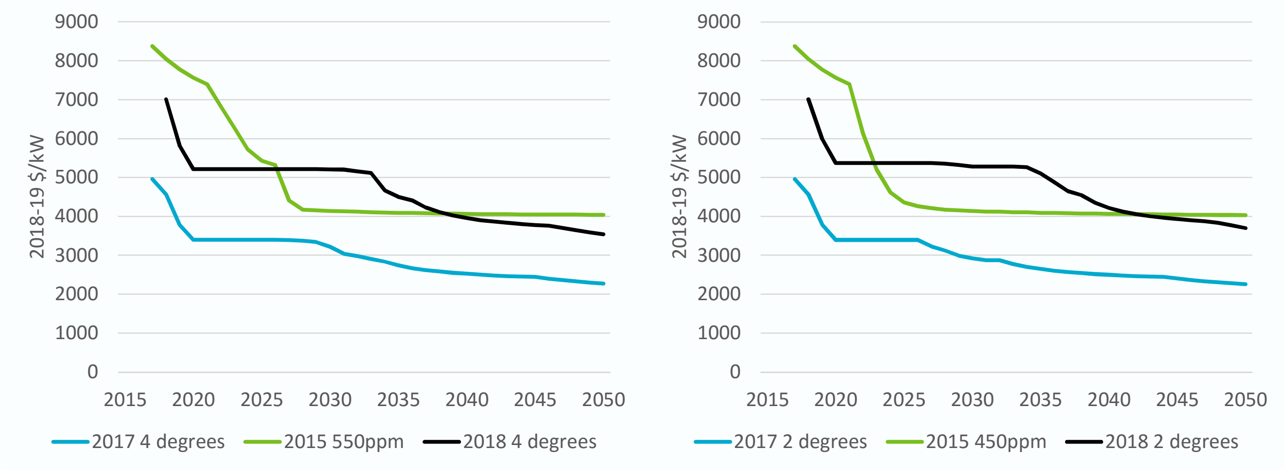


**Figure 3-10: Projected capital costs for solar thermal compared to two previous studies**

### 3.2.9 Large scale solar PV

Large scale solar PV is projected to experience a long term rapid decline in costs and this has been a feature of projections since 2015 (Figure 3-11). A key assumption underpinning this projection is that unlike other generation technologies the modularity of solar PV means that it can sustain a higher learning rate for longer than other technologies. As a general rule, most technologies have a falling learning rate as they reach different market share milestones. They begin with a high learning rate (e.g. 20% cost reduction for each doubling of cumulative capacity) but as they mature their learning rates declines until it is zero (and is a fully mature technology such as black coal supercritical).

Solar PV has historically shown the ability to not be bound by this general rule. The only other technology which behaves like this is batteries. The characteristic that these technologies have in common is their modularity (they can be easily applied at wide ranges of sizes) and their multiple applications. Solar PV is used in a wide range of appliances, in rooftop solar and in large scale power generation. Batteries are also used in wide range of appliances, in electric vehicles, in building energy management and in large scale generation storage applications. At some point, the learning rate will decline and we build in a minimum cost of around $500/kW in the long run for solar PV.

There is a trend across the studies compared of revising the starting value for solar PV downward. This contributes to the 2018 projection being lower than previous studies across both scenarios for most of the projection period.

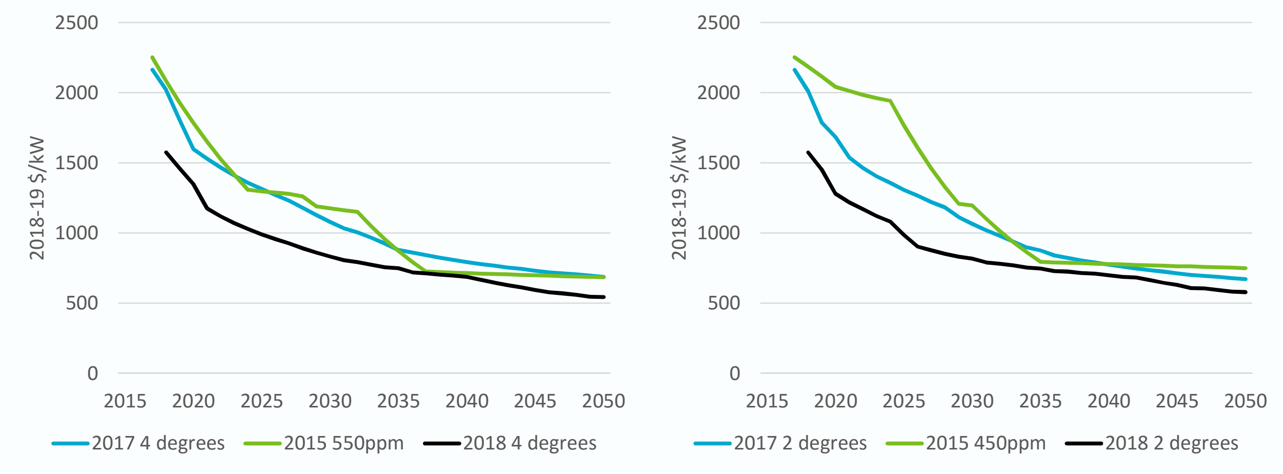


Figure 3-11: Projected capital costs for large scale solar PV compared to two previous studies

### 3.2.10 Rooftop solar PV

The solar panel component of rooftop solar PV installations shares learning in the projection model with large scale solar PV such that deployment of either leads to cost reduction in both. As a consequence rooftop solar PV shares the trend of a long term comparatively rapid decline in costs of large scale solar PV (Figure 3-12). As discussed in regard to large scale solar PV, the assumption that learning rates for solar PV do not decrease at the rates of other technologies underpins this projection.

CSIRO adjusted the starting value for rooftop solar PV to better reflect a 3kW size solar system. This is the main reason why the 2018 projections are higher than 2017. Rooftop solar PV costs are lower under the 4 degree scenario because higher electricity demand under that scenario supports greater solar PV deployment.

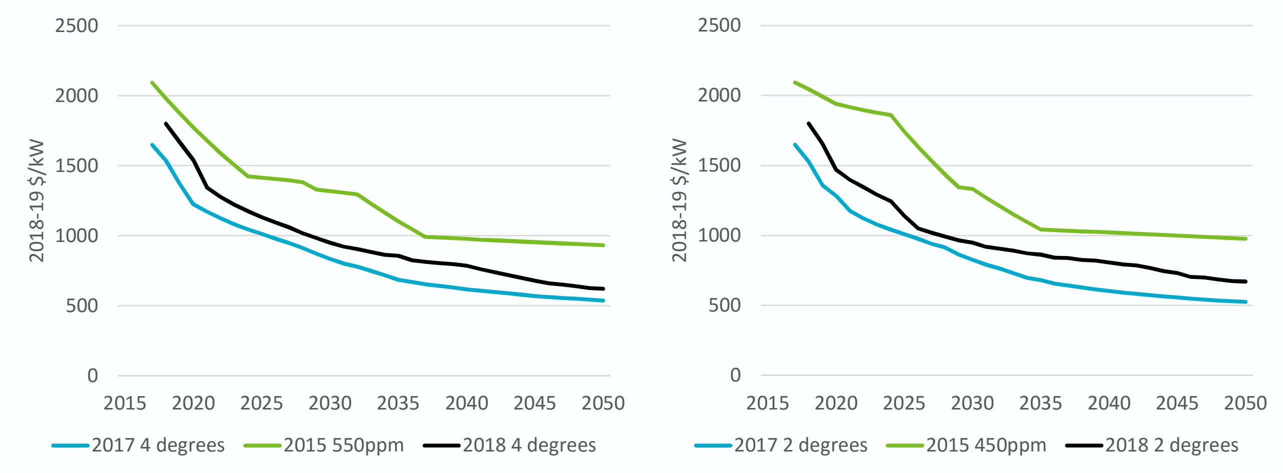


Figure 3-12: Projected capital costs for rooftop solar PV compared to two previous studies

### 3.2.11 Wind

Wind generation technology has been assigned a lower learning rate based on an observed slowdown in its historical cost reduction for each doubling in cumulative capacity. As a consequence, despite very significant deployment in both scenarios the rate of capital cost reduction is modest compared to solar PV (Figure 3-13). The downward trend is slightly stronger in the 2 degrees scenario which has a significantly higher share of wind generation and this result aligns strongly with the 2017 projection. The relative share of wind and solar PV is selected using an hourly model to ensure the combination of supply from variable renewables and flexible generation is able to meet demand. Under the 4 degrees scenario, since there is still considerable coal and gas generation, wind is less required to support low cost solar PV resulting in lower deployment relative to the 4 degrees scenario. Higher carbon prices under the 2 degrees scenario make coal and gas less attractive for system balancing and as a result more wind is deployed to assist in system balancing (not as a flexible technology but reflecting its non-coincident supply profile relative to solar PV).

While the capital cost of wind generation technology may not be improving as fast as solar PV we received a lot of input from stakeholders indicating that the levelised cost of wind generation is falling. There is broad agreement that this is due to larger wind turbines being deployed which are able to generate electricity at lower wind speeds resulting in higher capacity factors.

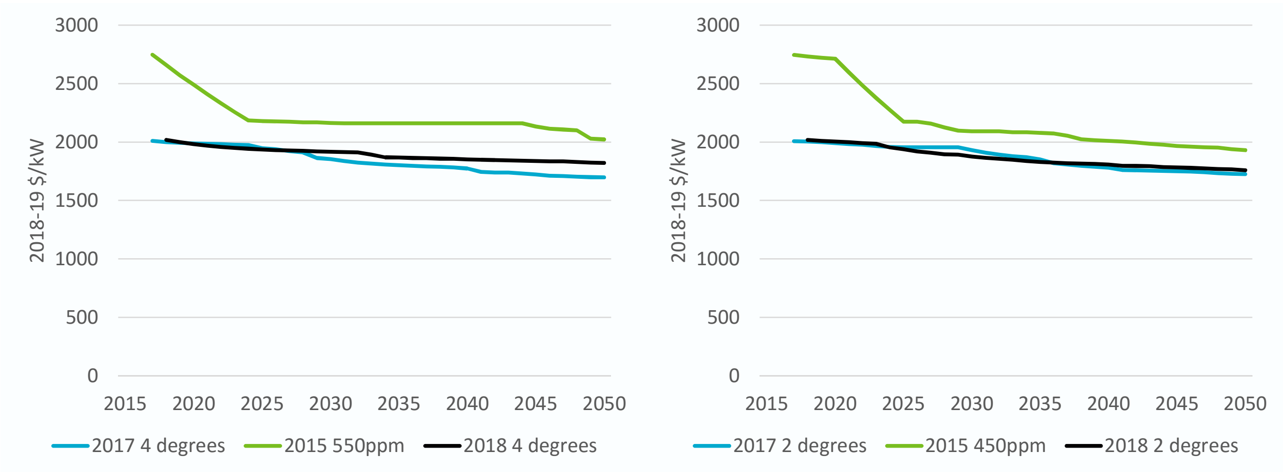


**Figure 3-13: Projected capital costs for wind compared to two previous studies**

### 3.2.12 Battery storage

CSIRO has previously prepared battery storage cost projections in 2017 (Hayward and Graham, 2017) and prior to that as part of the Electricity Network Transformation Roadmap (Brinsmead et al., 2017) and in a review of battery storage trends for the AEMC (Brinsmead et al., 2015). In Hayward and Graham (2017), the assumptions were changed to reflect the observation that batteries, like solar PV were not experiencing falling learning rates like other technologies normally do. As a result, the Hayward and Graham (2017) projection (in light blue in Figure 3-14) was substantially lower than those previous projections (green and dark blue). We focus on the battery pack costs because they are a shared component between the road transport and electricity sectors. Costs including balance of plant are provided in Appendix B.

For the 2018 projections, there has been another significant change in the projection approach in that the quantity of batteries being deployed to the power sector is defined in a separate linked hourly model for each global region. Also, in that model batteries are competing with pumped hydro energy storage whereas previously that technology was not included in the projection method.

Global electric vehicle projections have also been revised and these impact the early stages of battery cost reduction since deployment of batteries in large scale power generation applications is currently negligible compared to electric vehicles.

The combined impact of these changes in assumptions and the projection method is included in the 2018 projections (the black and grey lines in Figure 3-14). The 2018 projections show that battery deployment to the mid-2020s (mainly from global electric vehicle adoption) supports further rapid cost reductions but at a slower rate than projected in 2017. However, from 2025 in the 4 degrees scenario (2 years later in the 2 degrees scenario owing to lower electricity demand) the rate of cost reduction accelerates again indicating that this is the period where the power generation sector is likely to require significant scale of batteries. It is also the period where electric vehicles are widely expected to reach cost parity with internal combustion vehicles. As such, the combined impact of more rapid deployment in both the road transport and generation sectors leads to rapid deployment and subsequent cost reduction.

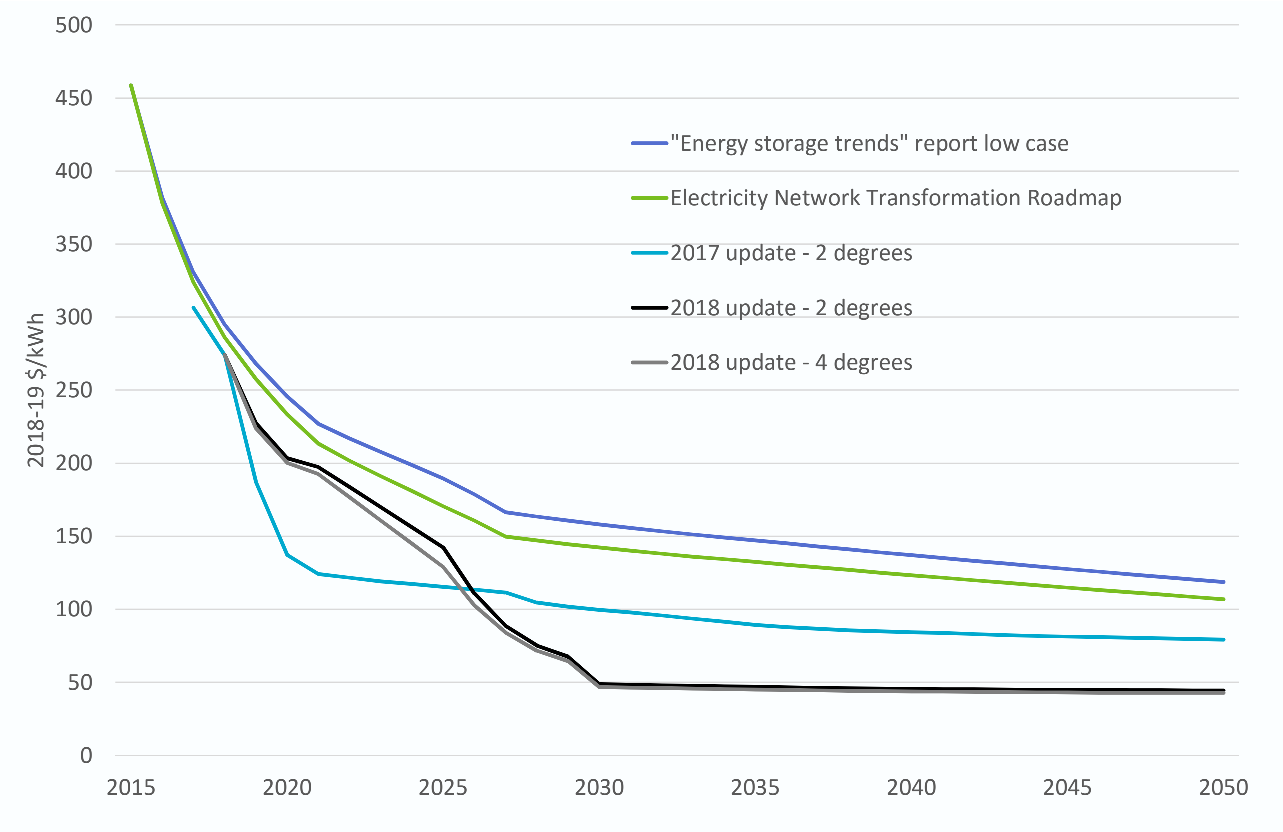


**Figure 3-14: Projected capital costs for battery pack compared to three previous studies**

The minimum point of the 2018 projections is around $50/kWh which is lower than that projected in 2017 ($67/MWh). This reflects that 2018 projections are including greater quantities of batteries than under the previous method which did not include hourly modelling and was therefore less able to determine battery requirements. The $50/kWh is not an imposed floor but rather the levelling out reflects that battery requirements are largely met by 2030s. This reflects that PHES becomes a more preferred storage technology over time as the requirement for longer periods of storage increases with the share of variable renewables. Also electric vehicle sales shares may be saturating (however the fleet share will continue to rise well beyond the 2030s as older internal combustion vehicles are slowly removed from the fleet).

### 3.2.13 Other technologies

The remainder of the electricity generation technologies not yet discussed have been grouped under Figure 3-15 (4 degrees scenario) and Figure 3-16 (2 degrees scenario). This group of technologies either do not have previous projections (e.g. fuel cells, PHES with 6 hours storage) or their adoption is low. For technologies such as wave, tidal, enhanced geothermal and biomass with CCS the prospects for significant adoption in the next ten years is poor. In our projection model, these technologies are generally only taken up in the 2030s and beyond in global regions which have limited resources of lower cost energy sources such as wind and solar or limited CCS storage sites.

Under both 2 degrees and 4 degrees scenarios wave generation technology receives significant uptake from 2030. Biomass with CCS is only taken up in small quantities but receives co-learning from deployment of fossil with CCS. Enhanced geothermal is only adopted in small amounts globally in the 2040s. Tidal power costs reduce with some near term projects that we were able to capture as model inputs. Thereafter cost reductions projected by the model stall until the 2040s when carbon prices are high enough to see further adoption.

Fuel cells experience steady cost reductions throughout the projection period. This is because, like batteries, we allow deployment of this technology in vehicles to count toward global cumulative capacity. Despite this assistance in achieving cost reductions, fuel cells do not achieve a large share in electricity generation.

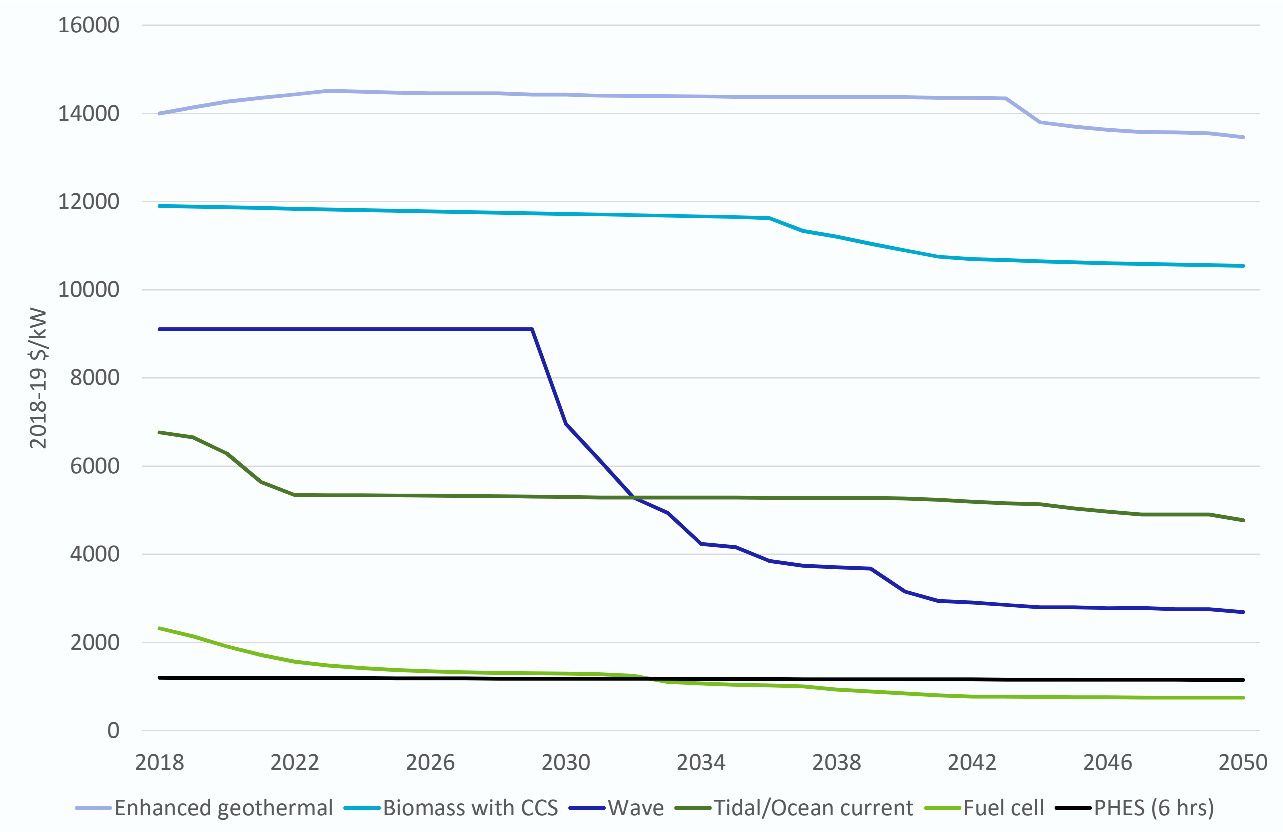


**Figure 3-15: Projected capital costs by technology under the 4 degrees scenario**

PHES with 6 hours storage has a fairly flat cost reduction trend. This is because most of the components are mature. The main component for which we allow learning from accumulation of capacity is tunnelling costs. PHES with 6 hours storage does achieve significant role in the electricity sector globally, however as tunnelling is a small proportion of costs, the overall trend remains flat.

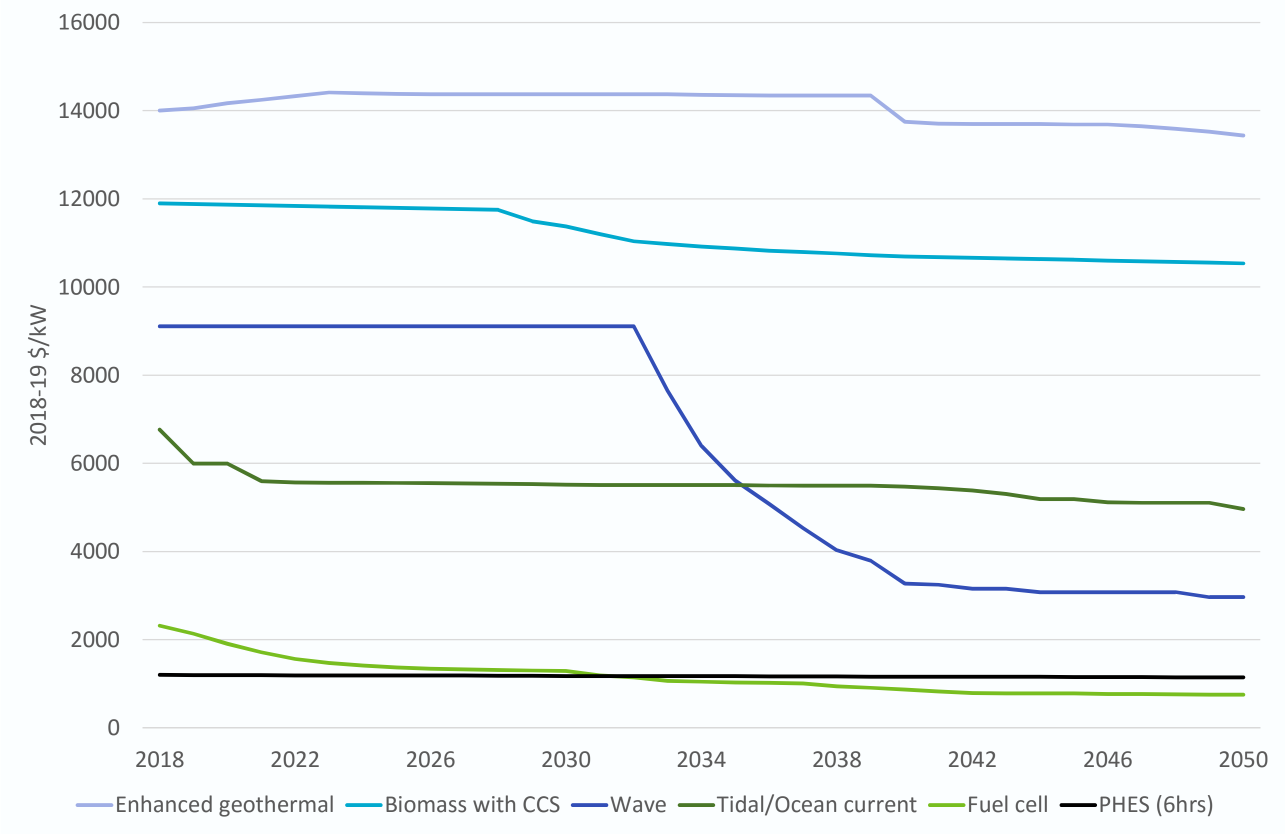


**Figure 3-16: Projected capital costs by technology under the 2 degrees scenario**

# 4 Focus topic A: LCOE and the need to extend methods to include system balancing costs

## 4.1 The role of levelised cost of electricity (LCOE)

To directly compare technologies using a common metric we have traditionally calculated their LCOE. Electricity generation technologies are characterised by a mix of capital (upfront investment) costs and operating costs such as fuel and maintenance costs. Some technologies are capital intensive with low operating costs (e.g. renewables) while others have higher operating costs (such as combined cycle gas turbines). LCOE converts all costs into annual operating costs (i.e. capital costs are amortised into equivalent annual payments), adds them together and divides them by annual output in energy terms, typically MWhs.

For those individuals and organisations who are familiar with the workings of electricity market models, and who have access to their own, maintaining a cost comparison method like LCOE is not a priority. Electricity market models take all the cost and performance inputs and calculate system price outcomes, the optimal technology mix over time and profits of each generation unit which together is a richer information source than LCOE. LCOEs are not used by AEMO in producing its Integrated System Plan (ISP).

However, for the much larger community of non-modeller electricity industry stakeholders who want to understand why electricity models give the results that they do, or why investors are making certain technology choices, an LCOE measure, until recently, has been considered a useful guide. While LCOE has performed this role in the past, it needs to be extended in light of the greater emphasis on variable renewables in the electricity system and their additional balancing costs which are not captured by LCOE calculations.

## 4.2 Emerging issues with traditional LCOE calculation

LCOE has always been applied to technologies that perform different roles, none of which on their own are designed to provide all electricity supply under all circumstances. For example, , some generators (coal, nuclear) cannot adjust quickly to changing load, but traditionally have a low operating cost, and other generation technologies are more able to respond to changing load, but traditionally operate at higher cost.

Another consideration is that, in regions with low variable renewable uptake, it is likely that the current system can absorb variable renewables using existing balancing capacity. As such, the LCOE may not be misleading at all in those regions at present. However, as the share of variable renewables rise, which is a high expectation given their continuing cost reduction, more balancing capacity will need to be added for system reliability purposes. Consequently, LCOE is expected to become increasingly less useful as a technology cost comparative measure and as an indicator of electricity prices.

Another concern in regard to LCOE is that it is becoming more difficult to justify applying the same weighted average cost of capital to technologies with very different climate policy risks. There are a range of solutions for this issue ranging from the simple (e.g. adding an arbitrary risk premium) to complex (e.g. adjusting costs by different carbon price scenarios). A universally accepted approach has yet to be agreed.

## 4.3 Interim LCOE results

Ultimately the GenCost project is seeking to move to an extended measure of LCOE which addresses the emerging issues discussed above. In the interim, given the potential for LCOE to be misleading for the reasons discussed, LCOE needs to be presented carefully and with many caveats. LCOE has been calculated in the discussion to follow using the updated cost and performance data included in this report and in GHD (2018) each decade from 2020 to 2050 in Figure 4-2, Figure 4-3, Figure 4-4 and Figure 4-5. The lowest and highest fuel cost assumptions across the scenarios and sensitivities explored in ISP 2018 for new plant have been used to construct a fuel cost range for use in the LCOE calculations. These assumptions are reported in Appendix B.

There are two primary issues for consideration when interpreting the LCOE data provided which we now address.

### 4.3.1 Consideration 1: Representing climate policy risk

While there is no explicit greenhouse gas emission cap on the Australian electricity sector, the Commonwealth government has an economy-wide emission reduction target of 26% below 2005 levels by 2030 and several state governments are targeting net zero emissions by 2050 (e.g. New South Wales, Victoria and South Australia). Some states also have renewable energy targets which increase the risk of stranding for existing and new non-renewable generation capacity. The technologies most at risk are fossil fuel technologies which do not capture and store their emissions. Brown coal is the most emission intensive followed by black coal and natural gas. New plant are less emission intensive than existing plant.

As discussed, there is no universally agreed method to take account of the climate policy risk faced by fossil fuel based electricity generation technology. To present a range of options, we calculate the LCOE for fossil fuel technologies in three ways: with no adjustment for climate risk, with a 5% premium added to their weighted average cost of capital (WACC)[9] and with a normal WACC but with a carbon price imposed consistent with carbon prices used elsewhere in this report for global technology cost projection purposes[10].

The results show that for black and brown coal, adjusting for climate risk using a 5% premium on the WACC adds more to generation costs in 2020 and 2030 than using a carbon pricing approach.

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[9] The 5% premium is selected based on Finkel et al. (2017) and Jacobs (2017), specifically Table 3 page 22 in the latter. No risk premium was used by AEMO in its 2018 ISP

[10] This should not be read to imply any particular climate policy framework for Australia. The carbon prices assumed reflect the general global greenhouse gas emission costs that may be faced by fossil fuel generators over time where Australia is participating in global efforts to curb greenhouse gas emissions.

In 2040 and 2050 when carbon prices have risen, using carbon prices directly to adjust for climate risk adds the most to new coal generation costs. This result is not particularly insightful since the risk premium for new plant should probably be adjusted up over time to be consistent with the intent of the Paris climate change commitments which indicate a desire to accelerate emission reduction efforts over time. However, no estimate of the likely change over time in the risk premium for fossil fuel generation is available.

Natural gas is less impacted by the climate policy risk premium on the WACC than coal because it is less capital intensive (but has wider range of fuel cost uncertainty). Natural gas is also less emission intensive. Consequently in 2020, the LCOE of gas generation is not significantly impacted by climate policy risk either in the form of a risk premium on the WACC or direct application of carbon prices. From 2020 to 2040, carbon pricing adds a maximum of $15/MWh to combined cycle gas costs each decade and $30/MWh in the final decade.

### 4.3.2 Consideration 2: Recognising differences in technology roles and abilities

To recognise differences in technology roles and abilities, the LCOE results presented here are divided into categories to indicate that technology cost comparisons within categories are appropriate but comparisons across categories should only be considered with caution or not at all. The first category is peaking defined as including technologies operating at 20% load (by which we mean capacity factor). In reality, peaking generation plant might have a capacity factor in a broad range (e.g. 5% up to 25%). We have chosen 20%, at the higher end of the range, for ease of representation on the same chart as other technologies. At the lower end of the capacity factor range, costs are very high in energy terms.

Open cycle gas plant and large hydroelectric generation are the two main plant that operate in peaking mode currently. However, with the potential for new large hydro generation[11] being low, we do not include them here. Gas reciprocating engines are used in land fill gas sites and other smaller applications in both peaking and larger capacity factor roles. Fuel cells are included because of their fast ramping capability but due to high current costs only become relevant in later decades as their capital costs fall and higher carbon prices increases open cycle gas costs. Even within the peaking category not all technologies perform the same services with some better equipped to provide faster response, the value of which LCOE is not well equipped to capture.

In the next technology category we have grouped together technologies which normally operate with a capacity factor in the range of 40 to 80%. The higher end of this range is sometimes termed “baseload” and indicates technologies which tend to maintain a fairly constant output for most of the day. At the lower end of this range we include solar thermal with 8 hours storage. This could have been included in the category of a “Variable” technology with storage. However, since solar thermal is never deployed without storage it fits better with the “Flexible 40% to 80% load” group.

Over time it is expected that there will be fewer technologies operating in baseload mode with high capacity factors. As the share of both behind the meter and large scale variable renewables

[11] Referring to a rain fed reservoir or river hydro generation rather than pumped hydro storage where a body of water is cycled between two reservoirs. The large Snowy 2.0 project is a pumped hydro energy storage project.

with near zero operating costs increases[12], it is more difficult for fossil fuel generation with positive operating costs to successfully compete to stay operating at all times of the day. As such, the cost ranges included for the fossil generators assumes a capacity factor range of 60% to 80%. From a technical perspective, the minimum-run requirement for these plant is 30% for gas and 40% for coal (GHD, 2018).

The next technology category is variable and includes renewable generation sources such as wind and solar photovoltaics. Wave power is another example of variable renewable generation. Carbon prices are not relevant to this category. The variable generation category is broken up into a standalone category and two categories which include 2 or 6 hours of storage capacity. 2 hours of storage capacity are achieved using battery storage while 6 hours of storage capacity are achieved using pumped hydro energy storage (PHES). Technically, the two different durations of storage could have been supplied by either technology. However, 2 and 6 hours more closely matches the competitive niches of battery and PHES respectively and secondly they more closely match how the underlying cost data was designed by GHD (2018)[13].

The storage levels of 2 and 6 hours was selected on the basis of previous research that has indicated the required amount of storage over time. Campey et al (2017) simulated rising variable renewable energy shares over time in National Electricity Market states and calculated the required amount of storage to ensure reliable supply[14] (Figure 4-1). The simulations indicated that little to no storage would be required up to 50% variable renewable energy share. However, at 50 to 75% variable renewable share, around 2-3 hours storage is required and up to 90% variable renewable share required up to 8 hours storage. Since GHD (2018) included PHES in a 6 hours storage configuration, this is a reasonable match for the case of 80-90% variable renewable share. We include the 6 hour case from 2020 but variable renewable share is unlikely to reach penetration levels this high until later decades, except perhaps in South Australia. South Australia is presently at around 50% variable renewables. State government policies in Queensland and Victoria are expected to move those states towards a 50% share by 2030.

[12] This outcome is fairly assured with strong trends in residential and commercial rooftop solar adoption and existing state and commonwealth renewable energy target policies.

[13] The cost information provided by GHD (2018) is not readily amenable to applying to storage plant configurations with different power to energy ratios.

[14] Note that the simulated weather year included a three week “renewable drought” which was sampled from historical data. However, the renewable drought was managed using gas generation peaking mode rather than storage. Storage is only part of a package of measures required to balance the system.

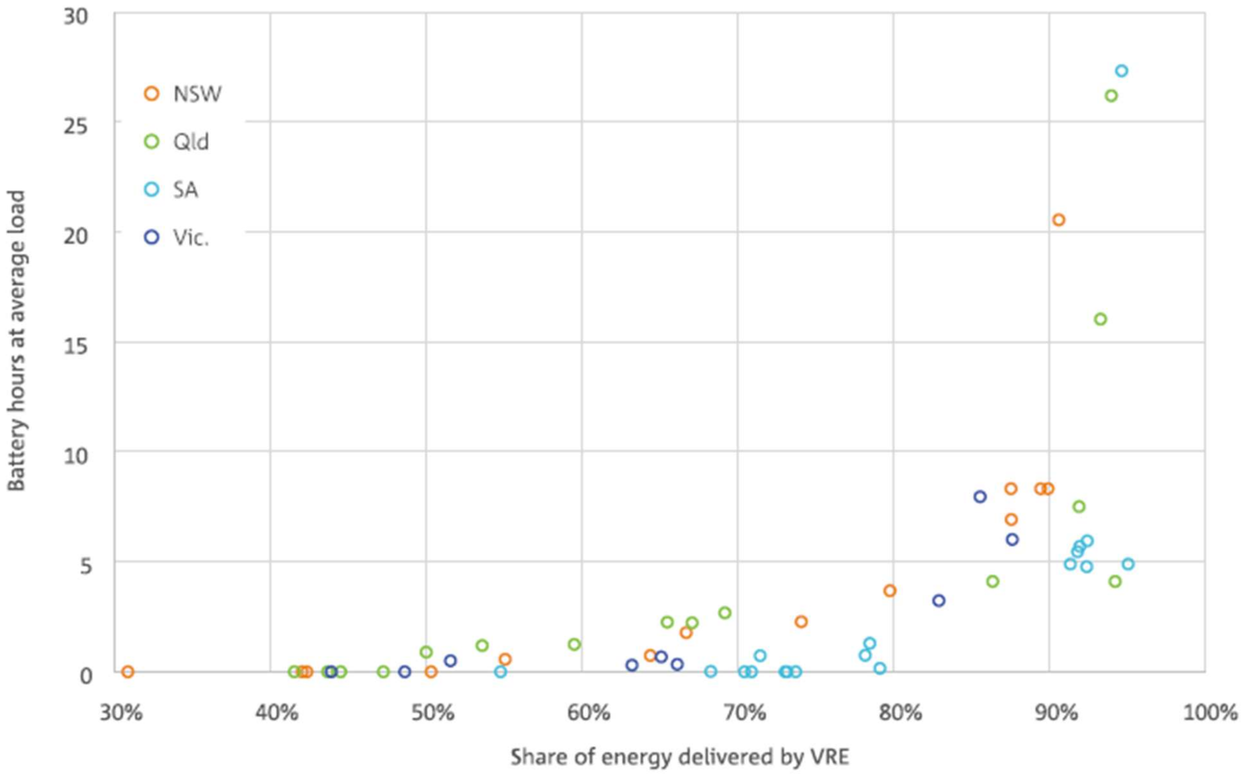


**Figure 4-1: Estimated hours of storage required by state for a given level of variable renewable energy share, Source: Campey et al. (2017)**

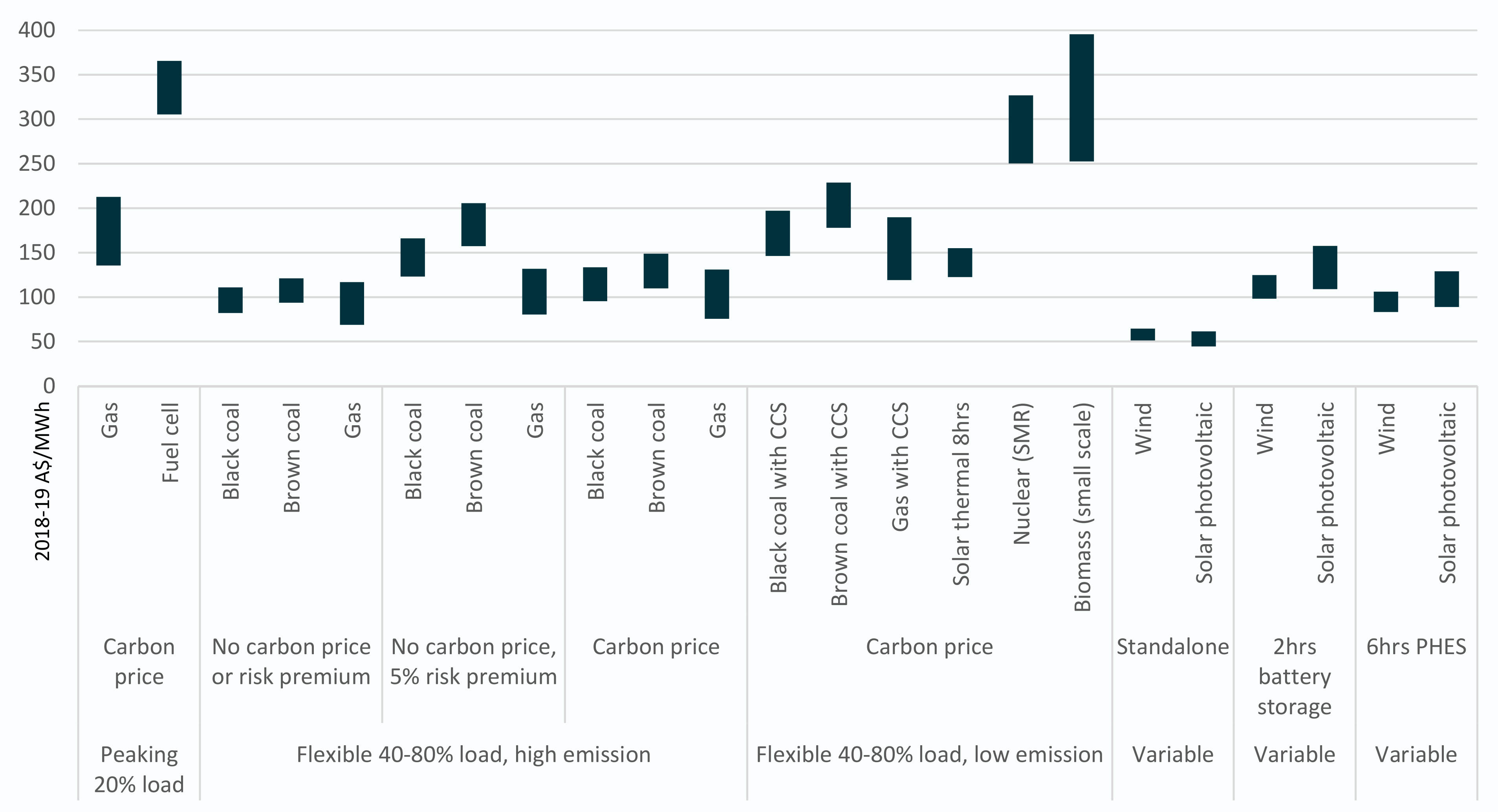


**Figure 4-2: Calculated LCOE by technology and category for 2020.**

**Notes: Ranges are primarily based on differences in carbon prices, capital costs, fuel costs and capacity factors (see Apx Table B.2 in Appendix B). PHES is pumped hydro energy storage; CCS is carbon capture and storage; SMR is small scale modular reactor. The gas peaking technology is an open cycle turbine, other flexible gas refers to a combined cycle gas turbine. Flexible coal refers to a supercritical pulverised fuel plant.**

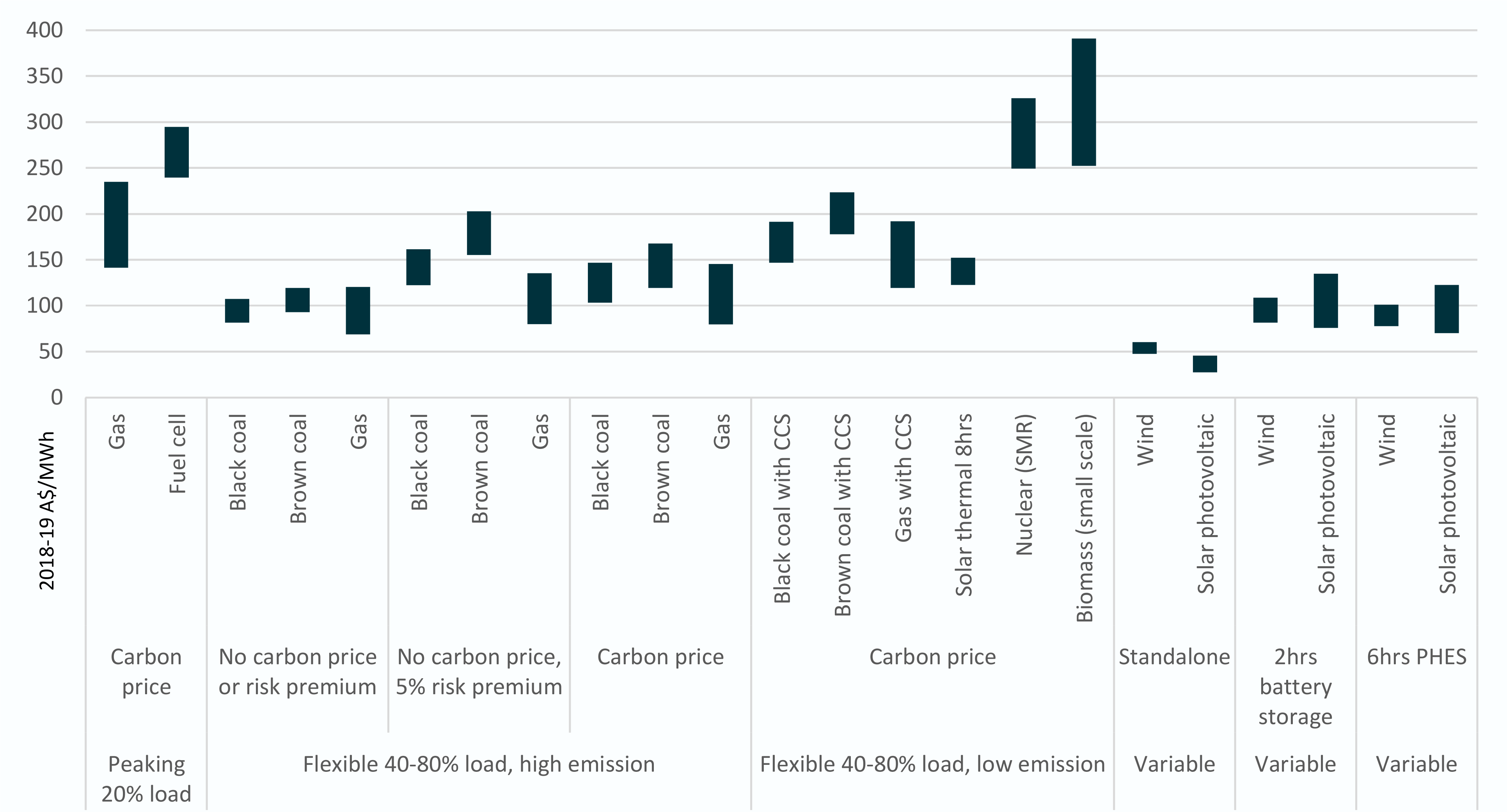


**Figure 4-3: Calculated LCOE by technology and category for 2030**

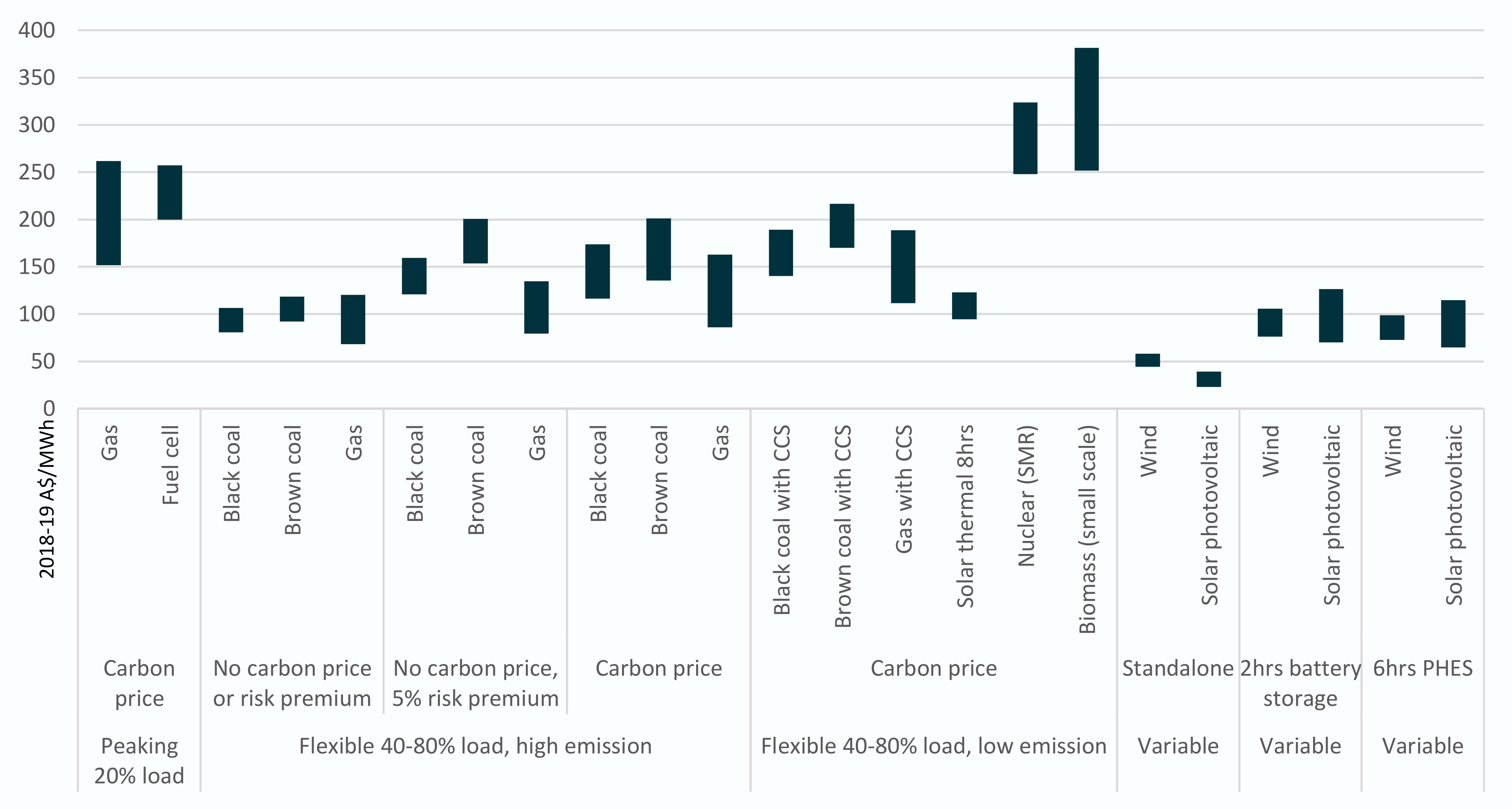


**Figure 4-4: Calculated LCOE by technology and category for 2040**

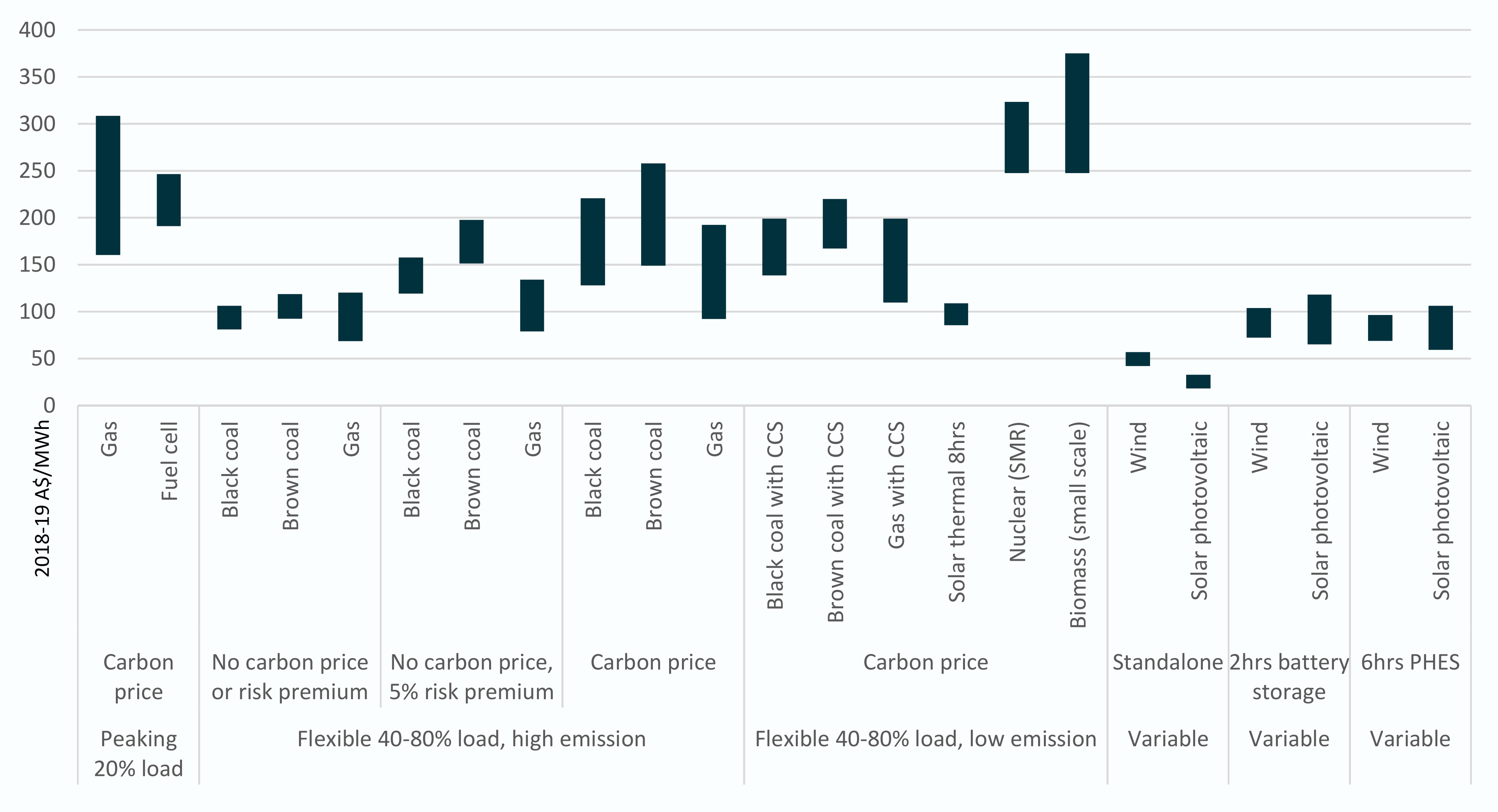


**Figure 4-5: Calculated LCOE by technology and category for 2050**

## 4.4 Interpretation of interim LCOE results

The use of different categories to separate technologies that perform different roles serves to highlight the limitations of LCOE. To avoid unfair comparisons, we have separated technologies into categories. However this undermines the central purpose of calculating LCOE, which is to have a broad method for comparing all technologies outside of a complex model. In particular, we would like a way to adjust variable renewables so that they can be compared directly with the flexible 40-80% load category. With the introduction of storage to provide firm hours of supply, the capacity factor of renewables is comparable with the low end of the capacity factor range of the flexible 40% to 80% load category. This hints at a way of making the categories comparable. However, adding an amount of storage to even up the categories is problematic from two perspectives. First, storage alone is not necessarily the least cost way of extending the capacity factor or improving the reliability of renewables. The fuller range of system balancing options for variable renewables include:

- Using the flexibility in existing generation stock
- Adding more non-coincident variable renewables
- Building transmission to connect to existing or new non-coincident variable renewables
- Making better use of existing demand management capacity or adding new capacity
- Gas peaking (which could include hydrogen and biogas, and potentially a switch to fuel cells long term).

Different combinations of these solutions will be least cost in different locations and times and depending on the type of variable renewable technology being added to the system.

The second issue with adding storage is the question of scale. We have chosen 2 hours and 6 hours partly based on previous modelling in Campey et al. (2017) and partly because the GHD (2018) storage cost estimates broadly aligned with these times. However, given the many other balancing options available (not all of which were included in Campey et al. (2017)) it is likely we are over-estimating the amount of storage required, particularly in the early decades. For example, adding non-coincident renewables as a first step would likely be lower cost than adding storage (assuming some spare transmission capacity in non-coincident zones). On the other hand, we could be under-estimating the amount of storage required in the context of very high variable renewable share scenarios in the later decades where storage of longer time periods may be required. Ultimately, the amount of system balancing solutions that need to be deployed with variable renewables is context dependent.

It is important to note that these system balancing requirements also apply to all of the technologies in the flexible 40% to 80% load category. We would not seek to run the electricity system on any one of these technologies alone. They all require support from peaking gas in particular and a mix of the other balancing solutions listed above to varying degrees.

## 4.5 Proposed way forward for a more useful LCOE

The interim LCOE results highlight that there are issues for the current approach to LCOE calculation in accounting for technologies with different climate policy risk and in making variable and flexible technologies comparable on a common basis. There are two ways demonstrated here for presenting climate risks (risk premiums and explicit carbon prices), however the solution for making flexible and variable technologies comparable is a much harder technical problem. As such, we are focussing our attention to the problem of how to extend LCOE by including the additional costs of balancing variable renewables. Our goal is to provide an extension to the LCOE calculation which takes into account balancing costs. In broad terms, balancing costs are about how system demand is met from a combination of technologies with a given amount of reliability. We do not include other system services that support stability, focussing only on reliability. Some technologies will require a different combination of balancing technologies due to their inherent qualities.

The amount of balancing required is context dependent rather than a simple formula. Therefore, we need a method or model that will calculate the minimum reliable amount of balancing costs from a menu of balancing solutions for a given context. Ideally, the solution for the amount of balancing costs should simply stack an additional amount onto the existing LCOE calculation as per Figure 4-6. Calculating that amount will involve calculating the optimal amount of additional balancing solutions and their costs. The technical challenge is to determine the most accurate and efficient new method to carry out that task.

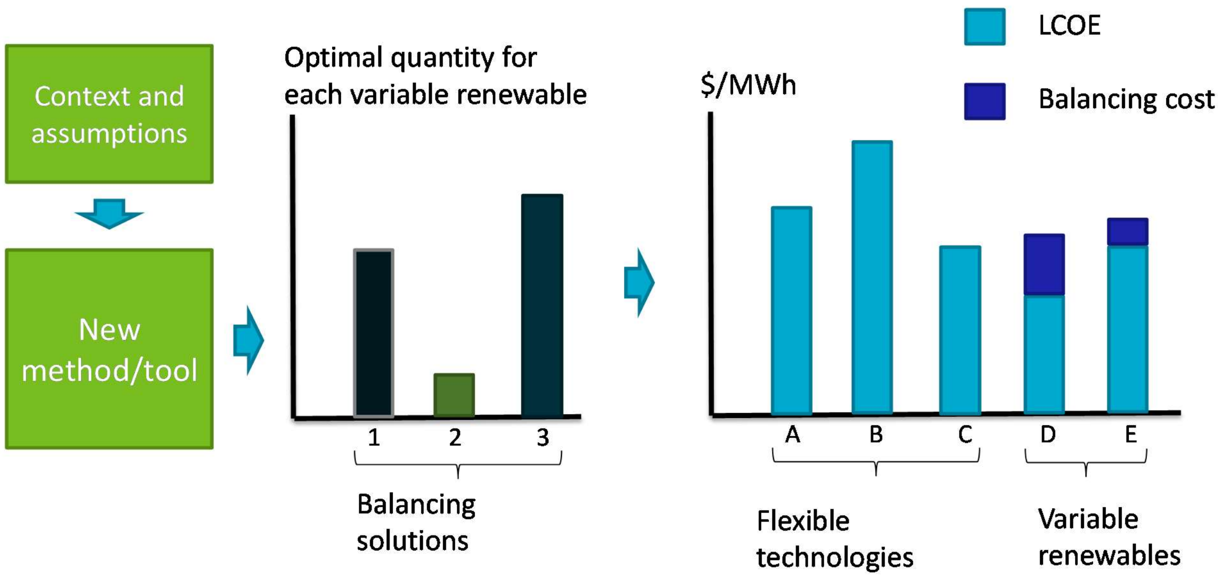


Figure 4-6: Schematic of proposed process for including system balancing costs in LCOE

### 4.5.1 Outcome of review of methods

A number of methods were reviewed to determine how to deliver the balancing cost estimate. The detailed review is published in Graham (2018) and it applied the following criteria to seven different methods available in the literature:

- **Breadth of firming solutions considered:** More is better
- **Inclusion of context:** The cost of firming depends on how much firming is needed. Determined by existing plant, time and location.
- **Transparency and repeatability:** The more complex a method becomes the less transparent and repeatable will be the method.
- **Technology specificity:** Balancing costs are a system property whereas conventional LCOEs are a technology property. Ideally a method should include a way of reconciling the system costs back to a specific technology.

The outcome of the review was that available methods existed along a spectrum of approaches ranging from simple technology modelling with limited or no context and one or two balancing solutions[15] to complex system models with detailed context and multiple balancing solutions (Figure 4-7). Complex system models are the most accurate but require high level quantitative modelling skills unlike conventional LCOE calculations which include a small number of equations and can be performed in spreadsheet software by a broad range of stakeholders. Simple technology models can be presented and carried out by a broader range of stakeholders but the result may be too inaccurate due to their lack of context and limited range of balancing solutions included.

CSIRO proposes to continue to explore development of a system modelling approach, but has presented interim LCOE results for variable renewable technologies with storage in this report. The existing system modelling approaches available in the literature do not include all the necessary balancing solutions or optimise their selection and operation. Optimising the selection and operation of balancing solutions requires a particular combination of forward-looking and high temporal resolution electricity system modelling framework. This combination of features is not typically included in the same electricity system model. Rather, the conventional approach is to model forward-looking investment decision making in a 30 to 50 year annual time horizon model. Half to one hourly modelling is performed in a present looking framework where the current supply is solved for demand in each time period sequentially. AEMO’s 2018 ISP, went a long way towards bridging this modelling gap, using forward looking time horizons with sub-daily demand steps to select a portfolio of diverse variable renewable generation, flexible thermal generation, transmission, and energy storage to meet future power system needs reliably and at lowest cost.

[15] See, for example, Lovegrove et al. (2018a) and (2018b)

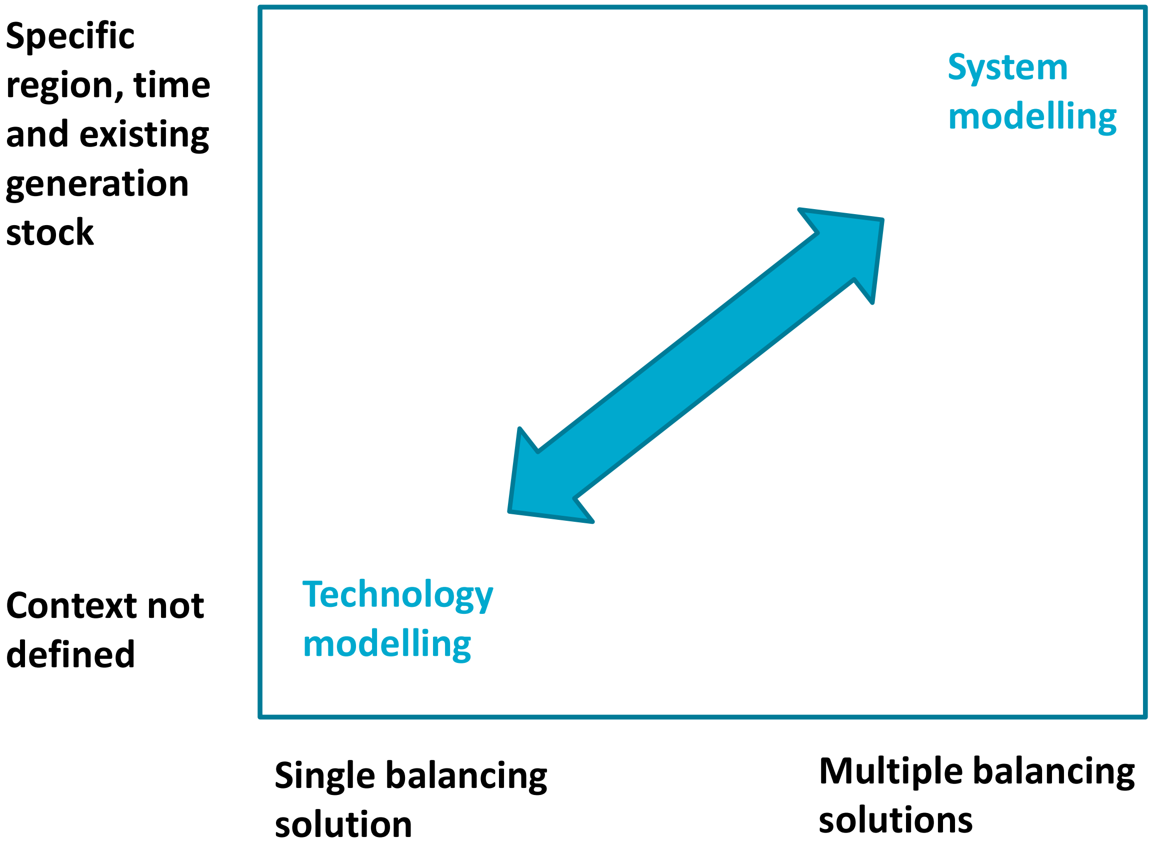


Figure 4-7: Summary of spectrum of methods available for calculating balancing costs

Two other lessons that emerged from the review of system methods in Graham (2018) and in GenCost workshop discussions. First, in exploring each technology, it would not be appropriate to simply add more of a single variable renewable electricity technology. The system model should make available the option to add other variable and flexible technologies as part of the set of balancing solutions. Second, results are only valid for scenarios where adding variable renewables fills a supply shortfall. As such, the program of retirement of existing capacity will need to be part of the specified context.

# 5 Focus topic B: Extending GenCost to include demand management

## 5.1 Inclusion of demand management

As a long-term goal, the GenCost project would like to present demand management cost information as a competing technology to electricity generation. While the system already includes a modest demand management component, higher electricity prices (or volatility in prices), higher shares of variable renewables accompanied by retiring generation, some recent substantial electricity supply outages and the greater potential for more grid connected and automated demand management enabled devices means that demand management could play a larger role in the future.

The potential roles for demand management are outlined in Figure 5-1 which is a framework originally presented by Piette et al. (2008). At its slowest and least dynamic, demand management begins with energy efficiency, which affects the total energy used and potentially the power rating required to deliver a service from various customer equipment and appliances. Energy efficiency improvements may have a greater or lesser correlation with peak demand – for example, improved efficiency of cooling appliances will have greatest effect on hot days. As we move towards optimising the timing of the use of that equipment, control systems are required and some information about when electricity system demand is peaking may be required. The emphasis is on shifting services rather than reducing them. At the far end of spectrum, demand management may contribute to real time electricity system services requiring fast response. These require direct system or automated control and fast communication. Service levels may be reduced rather than shifted since the interruption is short duration.

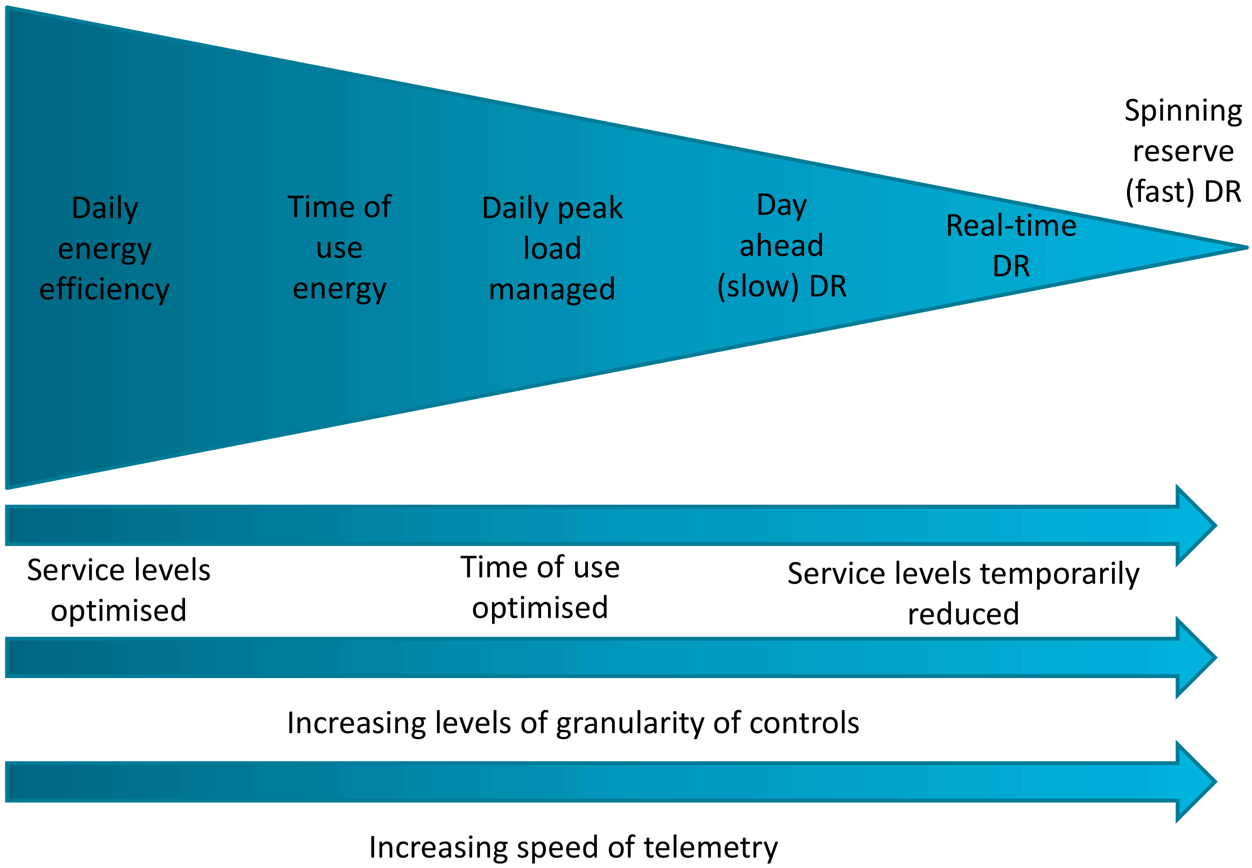


**Figure 5-1: Changes in service levels and controls as demand management delivers various roles in the electric sector. Source: Piette et al. (2008)**

The more of the services demand management provides along the spectrum, the less generation capacity may be required. It is therefore important that system planners and investors can understand the opportunities for cost effective demand management. While the potential for permanent shifts in total energy use are important, energy efficiency is out of scope for GenCost.

## 5.2 Priorities for understanding demand management costs

The potential for demand management can be assessed at a sectoral level, such as large industrial, manufacturing, commercial, residential and road transport. Within these sectors the challenge is to identify the highest return-on-investment opportunities and those with reasonably high replicability. For example, heating and cooling services include a limited set of well understood technologies. Also, we might consider commercial buildings management before residential if data indicated the opportunity for deployment was larger in that sector.

The key data parameters required to have sufficient information to include in modelling exercises are:

- Establishment cost, dispatch cost
- Volume available (MW, MWh)
- Time profile of availability (i.e. what days or seasons does the energy use occur, and when is it 'interruptible')

- Available locations
- Level of 'firmness' at site level or portfolio level including statistical measures of performance in practice
- Establishment lead time
- Dispatch lead time
- Allowable frequency of calls.

Some of these are relatively straight forward in that they relate to specific properties of the operating equipment. However, others depend on the customer's changing circumstances.

## 5.3 Existing estimates of demand management costs

The following provides a brief summary of several existing sources of information on demand management costs and the method under which the information was gathered.

### 5.3.1 ARENA/AEMO funding round contracted projects

ARENA and the Australian Energy Market Operator (AEMO) have awarded funding to ten pilot projects under a demand response program aimed at managing electricity supply during extreme peaks. The $35.7 million initiative is intended to deliver 200 megawatts (MW) of capacity by 2020, after an initial capacity of 143 MW captured in 2017. The selected projects, shown in Table 5-1, have an average price of $0.06m/MW/year and will be called upon a maximum of 10 calls per year of up to 4 hours each.

As this is a relatively novel program we could infer these costs include a first of a kind premiums. However, the cost data is fairly reliable in the sense that these are real projects. The data is publicly available reflecting the investment of ARENA. Demand response trials funded by state governments or network companies may provide similar data. It is not clear if data from commercial demand management procurement processes will be as transparent.

**Table 5-1: Capacity and cost of demand response projects**

| Supplier | Initial capacity (MW) | 2020 capacity (MW) | Cost ($m) | $m/MW per year |
|---|---|---|---|---|
| **United Energy** | 12 | 30 | 5.8 | 0.08 |
| **EnerNOC** | 50 | 50 | 9 | 0.06 |
| **Intercast & Forge** | 10 | 10 | 0.3 | 0.01 |
| **EnergyAustralia** | 38 | 50 | 9.8 | 0.07 |
| **Flow Power** | 5 | 20 | 2.6 | 0.06 |
| **AGL** | 18 | 20 | 5.2 | 0.09 |
| **Zen Ecosystems** | 5 | 15 | 2 | 0.06 |
| **Meridian Energy** | 5 | 5 | 1 | 0.07 |

**Source: https://arena.gov.au/blog/demand-response-4/**

### 5.3.2 ClimateWorks industrial demand side management estimation

ClimateWorks (2014) directly interviewed industry and related experts to determine the potential for demand management in that sector. This analysis has estimated 3.1 GW of demand management potential. Specifically, demand management categories tested were for the ability to shift or shed load for a period of 2-4 hours, 5-10 times a year during a network or electricity system peak. The amount of demand management represented 42% of the 7.6GW contribution of these sectors to system peak (summer weekdays between 2pm and 7pm) at the time of the interviews.

This level of demand management was stated as being available in exchange for 20-30% off of their full year electricity bill (for MWs committed). This was considered to be at the high end of potential returns for demand management suppliers. However, 50% of the identified potential, or 1.7 GW, was indicated from interview responses to still be available if the incentive was only 5-15% of a participant's total electricity bill. This lower incentive was considered to be closer to incentives offered currently in Western Australia and international markets. Competing business priorities, lack of internal skills and lack of long term incentives were discussed as reducing the ability to access demand management potential.

The analysis of demand management potential is very detailed, including over 20 industry subs-sectors and just over 30 individual industry processes. Broad categories include compression, process heat, chemical processing and material handling.

While this approach provides rich data on demand management opportunities, the interview approach for gathering such data includes a cost and the response represent intentions rather than real project commitments.

### 5.3.3 Regulatory impact statements relating to demand management and smart appliances

The Equipment Energy Efficiency Committee of COAG (2013) calculated the cost of demand management in the event that air conditioners, pool pumps, electric water heaters and electric vehicle chargers were mandated to include the Australian and New Zealand standard 4755 demand management communication protocol interfaces.

They found that incorporating interfaces would add less than 1 per cent of the price for air conditioners and water heaters and 2 to 3 per cent for swimming pool pumps and controllers. With the interface in place, the other costs to enable demand management include activation costs which were estimated to be in the order of $50 to $180 per appliance plus $20 per year for the duration of participation. Subsequent appliances would have reduced upfront activation costs of 70% to 80% and 50% lower annual costs. Retrofitting demand management capability without the standard interface was estimated to be substantially more costly - for an air conditioner to enable direct load control, electrical re-wiring could cost around $1,500. As at 2018 the standard interface is voluntary for appliance manufacturers, meaning there would be a mix of 'standard interface' and 'retrofit' costs in the real world.

This represents a bottom up approach to calculating the costs of delivering demand management in major building appliances. While it captures all of the material costs it does not estimate the value customers place on continuous operation of their appliance without interruption during a peak event. It notes that customers who include their air conditioner in a demand management contract would experience a rise in temperature during a peak event that may not be recovered to original conditions for some time. Whether a change in temperature leads to a decline in comfort will depend on factors such as occupant expectations, starting temperature, the thermal buffering effect of the building envelope and the length of a demand management 'event'.

Providing some practical experience on the value customers place on continuous operation, Energex (currently part of Energy Queensland), implemented (and continues to make available) their PeakSmart air-conditioner scheme which makes use of the demand management standard. Energex pays participating customers a one-off payment of $200 for air-conditioners that are 4-10kW and $400 for systems greater than 10kW to include their air-conditioner in the scheme. Once included, the air-conditioner becomes available to be switched to a lower power operating mode during peak events a few times a year (e.g. 5 events in 2018, 4 in 2017). The Demand Response Modes (DRM) implemented depend on how extreme the need for demand management becomes and include DRM1: Compressor off, DRM2: capped to operate at 50% of rated power and DRM3: capped to operate at 75% of rated power. All 2018 events used DRM2. An equal share of events used DRM2 and DRM3 in 2017.

To enter the scheme customers need to either buy an air conditioner compliant with the standard or simply enter the scheme if their existing appliance is compliant. A signal receiver device also needs to be installed. There are around 70,000 customers signed up to the scheme[16].

For hot water and pool pumps, Energex offers a $200 reward for customers as an incentive to switch over to a tariff that manages devices connected to a controlled circuit with a separate meter. There is an upfront meter installation cost but the customer derives ongoing benefits by access to lower off-peak rates.

### 5.3.4 Value of customer reliability estimates

The value of customer reliability (VCR) is the value different customers place on having a reliable electricity supply. Like demand management it depends on the frequency and duration of an interruption in supply and the uses of energy by the customer (or supplier in relation to demand management). The concept is relevant to estimating the cost of demand management because in a sense VCR sets the maximum the system should be willing to pay, on behalf of customers, to avoid an outage. Any demand management costs above this level are irrelevant. Further, if VCR is estimated for different groups of customers, an upper bound 'supply curve' for demand management can be constructed.

VCR estimates are also relevant to demand management costs because a lot of the methods for calculating VCR could be modified slightly to be relevant for estimating demand management costs. The AER (2018) is currently reviewing methods for this. They include direct cost surveys, the economic principle of substitution, contingent valuation surveys, choice modelling and model-based methods.

[16] https://www.energex.com.au/home/control-your-energy/managing-electricity-demand/peak-demand/peaksmart-events

For demand management, these costs also indicate the minimum a customer would need to be paid to compensate them for a 100% withdrawal of their demand[17]. Note, from our discussion above it would be better to also ask customers costs for less extreme cases such as those associated with the various demand management protocol standards (25% and 50%). Nevertheless, this is a potential data source for some demand management costs and depending what the AER review of VCR estimation methods concludes, could inform the method used to gather other demand management data.

### 5.3.5 Other information sources

There are several other relevant information sources that could influence how we approach developing demand management costs. The Energy Use Data Model (EUDM) is making more customer end-use data available over time including cross-referencing demand profiles with other data and conducting a variety of customer energy end-use surveys on a rolling basis. This may open up the scope of estimation methods that can be applied.

AEMO has established a process for electricity industry participants to submit demand side participation information, in accordance with a Rule made by the AEMC in March 2015. The intent is to improve the information available for electricity load forecasts. However, in the context of the GenCost project, the information collected relates to currently-active demand side participation rather than an assessment of future potential.

It should also be acknowledged that there is an existing body of literature on price responsiveness of demand which draws on a wide range of tariff trials in Australia and worldwide. These include longitudinal data on the extent to which responses are maintained over longer periods. These mainly relate to how households would respond to price signals discouraging consumption during peak times since most medium to large commercial and industrial customers already have such signals in their tariffs.

Related to the question of responsiveness of demand to tariff incentives is the emerging source of demand management of behind-the-meter battery storage. Battery storage is a particularly interesting form of demand management because it is highly scalable and opens up the possibility of customers responding to demand management requests without the need to modify their use of energy (instead the battery responds by using stored electricity on site to maintain services). There are several issues emerging from observation of this emerging market (based on Graham et al (2018)):

- Battery storage has a long payback period (10-16 years, not including subsidies that have been announced at the end of 2018) and, in terms of the typical consumer technology adoption curve, battery storage is an early adopter market (i.e. financial returns are not the prime motivator of adoption). Modelling market depth therefore requires understanding the proportion of the population who may be early adopters, and when batteries will switch from an 'early adopter' to 'financially-motivated' market segment.

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[17] It is an indicator only. Asking a customer what costs they incur from an outage may not elicit the same response as asking a customer what payment they would require to accept an outage at their site that is deliberate rather than as a result of a system fault.

- Optimising financial returns from battery storage typically involves signing up to a time of use tariff which provides a specific fixed incentive to shift electricity consumption away from a defined peak period and into a defined off-peak period. At low battery adoption levels, this approach to incentivising battery demand management is beneficial to the grid. However, if maintained over the long term with much higher battery storage adoption it could lead to problems because it encourages coincident battery charging at the tariff boundary periods.
- When time of use tariffs become no longer appropriate because of their incentivisation of coincident battery charging peaks is not known and nor is it clear what new incentive scheme will replace them. It may be that battery owners will sign up to a more general service agreement with a fixed rebate for control of their battery which is then operated by an aggregator which participates in a market with prices that are updated on closer to a real time basis. Note that, under a flat tariff, a customer would still have the incentive to purchase batteries to shift their rooftop solar PV away from low priced grid export payments. However, there is no particular incentive to maintain charge to cover peak events at times of low solar input, meaning battery owners could have drained their battery before the peak event ends.

## 5.4 Conclusions

Recent increases in the cost of electricity, recent supply outage events, an expectation of an increased need for balancing services as variable renewable energy shares increase and conventional generation retires and the potential for highly scalable adoption of battery storage, have increased interest in understanding the cost and scale of demand management service that could be available in Australia. As they represent a competing technology to adding more generation technology capacity we have conducted a preliminary review to consider methods to add demand management costs in future GenCost reports.

We find that, because demand management exists along a spectrum, varying with response time and impacts on customer service levels, there will be a wide range of demand management roles that would need to be separately costed to include them all. This represents a challenge for resourcing the collection of cost data, and reinforces the need to prioritise information on larger, closer-to-commercial opportunities.

On the other hand, there is a reasonable baseline of existing data. Trial results, past procurements and surveys already provide costs for industrial demand management. Networks, retailers and energy service companies offer a variety of deals from rebates to time of use tariffs to attract residential customers to participate, in demand management. The amount of demand management available at these costs, however, is limited by the adoption of enabled appliances and customer’s interest in taking up the available incentives. While expected to grow, at present, only a small proportion of the population (e.g. 70,000 PeakSmart participants in Queensland, around 30,000 battery storage owners nationally in 2017) participate in such programmes.

Whatever the methods that are employed in the GenCost project to estimate the cost of demand management they need to be relatively automated and not too resource intensive as the emphasis is on creating a repeatable, regular electricity cost update service to stakeholders. The review of existing data suggests that there are a mix of methods employed to gather demand management costs data including various survey techniques, direct tender for demand management services and model-based approaches which calculate the bottom-up cost of equipment required to deliver the demand management (these are most useful when the service impacts are small and indirect costs are therefore less relevant).

Given the range of demand management categories is so wide and there is existing data for some of them, we conclude that the next step is to prioritise which categories of demand management should be included in GenCost. For each category, the decision tree should consist of three options: use existing data, develop a low cost repeatable method or exclude if no low cost method is available. This prioritisation will be presented for feedback before implementation in future annual updates.

# Appendix A Capital cost projection with GALLM

## A.1 GALLM

The Global and Local Learning Models (GALLMs) for electricity (GALLME) and transport (GALLMT) are described briefly here. More detail can be found in several existing publications (Hayward & Graham, Electricity generation technology cost projections 2017-2050, 2017) (Hayward & Graham, 2013) (Hayward, Foster, Graham, & Reedman, 2017).

### A.1.1 Endogenous technology learning

Technology cost reductions due to 'learning-by-doing' were first observed in the 1930s for aeroplane construction (Wright, 1936) and have since been observed and measured for a wide range of technologies and processes (McDonald & Schrattenholzer, 2001). Cost reductions due to this phenomenon are normally shown via the equation:

$$IC = IC_0 \times \left(\frac{CC}{CC_0}\right)^{-b},$$

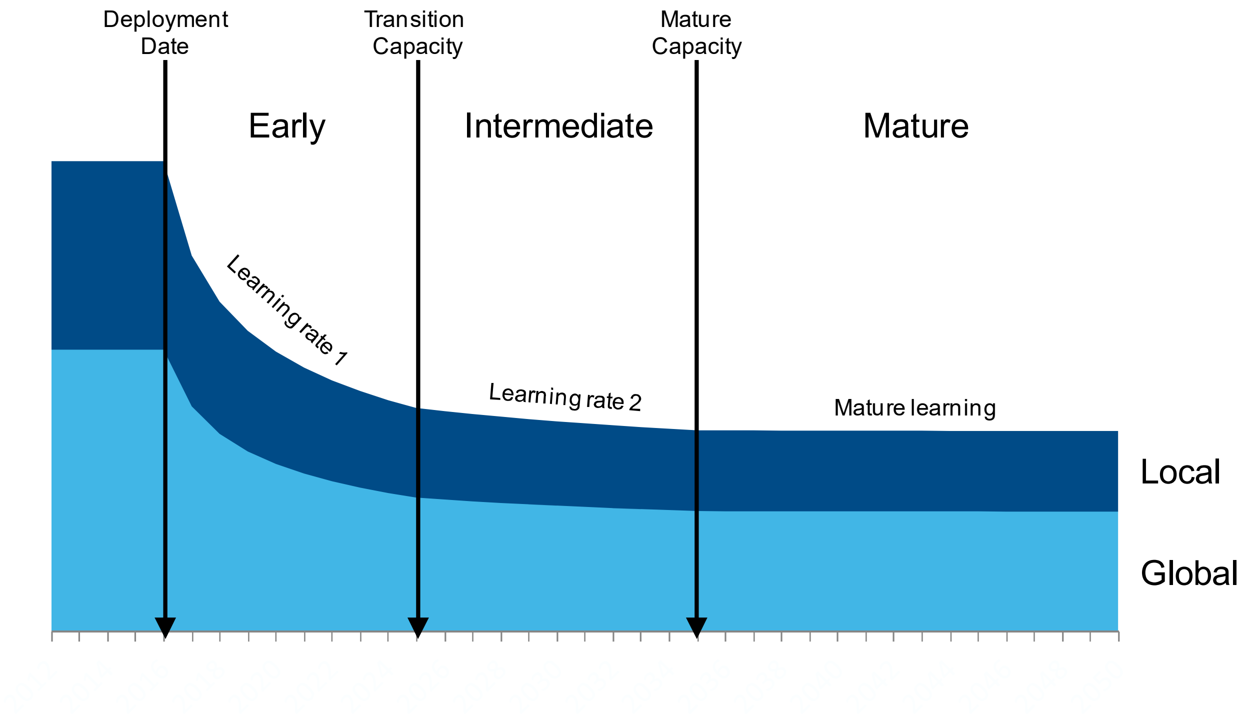
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

where *IC* is the unit investment cost at *CC* cumulative capacity and $IC_0$ is the cost of the first unit at $CC_0$ cumulative capacity. The learning index *b* satisfies 0 < *b* < 1 and it determines the learning rate which is calculated as:

$$LR = 100 \times (1 - 2^{-b})$$

(typically quoted as a percentage ranging from 0 to 50%) and the progress ratio is given by $PR = 100 - LR$. All three quantities express a measure of the decline in unit cost with learning or experience. This relationship says that for each doubling in cumulative capacity of a technology, its investment cost will fall by the learning rate (Hayward & Graham, 2013). Learning rates can be measured by examining the change in unit cost with cumulative capacity of a technology over time.

Typically emerging technologies have a higher learning rate (20–15%), which reduces once the technology has at least a 5% market share and is considered to be at the intermediate stage (to ~10%). Once a technology is considered mature, the learning rate tends to be 0–5%. The transition between learning rates based on technology uptake is illustrated in Apx Figure A.1.




**Apx Figure A.1: Schematic of changes in the learning rate as a technology progresses through its development stages after commercialisation**

However, technologies that do not have a standard unit size and can be used in a variety of applications tend to have a higher learning rate for longer (Wilson, 2012). This is the case for solar photovoltaics and historically for gas turbines.

Technologies are made up of components and different components can be at different levels of maturity and thus have different learning rates. Different parts of a technology can be developed and sold in different markets (global vs. regional/local) which can impact on the cost reductions as each region will have a different level of demand for a technology and this will affect its uptake.

### A.1.2 The modelling framework

In order to project the future cost of a technology using experience curves, the future level of cumulative capacity/uptake needs to be known. However, this is dependent on the costs. The GALLMs solve this problem by simultaneously projecting both the cost and uptake of the technologies. The optimisation problem includes constraints such as government policies, demand for electricity or transport, capacity of existing technologies, exogenous costs such as for fossil fuels and limits on resources (e.g. rooftops for solar photovoltaics). The models have been divided into 13 regions and each region has unique assumptions and data for the above listed constraints. The regions have been based on Organisation for Economic Co-operation Development (OECD) regions (with some variation to look more closely at some countries of interest) and are: Africa, Australia, China, Eastern Europe, Western Europe, Former Soviet Union, India, Japan, Latin America, Middle East, North America, OECD Pacific, Rest of Asia and Pacific.

The objective function of the model is to minimise the total system costs while meeting demand and all constraints. The model is solved as a mixed integer linear program. The experience curves are segmented into step functions and the location on the experience curves (i.e. cost vs.

cumulative capacity) is determined at each time step. See (Hayward & Graham, 2013) and (Hayward, Foster, Graham, & Reedman, 2017) for more information. Both models run from the year 2006 to 2100. However results are only reported from the present day to 2050.

### A.1.3 Technologies and learning rates

GALLME projects the future cost and installed capacity of 28 different electricity generation and energy storage technologies. Where appropriate, these have been split into their components and there are 44 different components. Components have been shared between technologies; for example there are two carbon capture and storage (CCS) components – CCS technology and CCS construction – which are shared among all CCS plant technologies. The technologies are listed in Apx Table A.1 showing the relationship between generation technologies and their components and the assumed learning rates (learning is on a global (G) basis, local (L) to the region, or no learning (-) is associated).

**Apx Table A.1: Assumed technology learning rates.**

| Technology | Component | LR 1 (%) | LR 2 (%) | Reference |
|---|---|---|---|---|
| **Coal, pf** | - | - | - | |
| **Coal, IGCC** | G | - | 2 | (International Energy Agency, 2008; Neij, 2008) |
| **Coal/Gas/Biomass with CCS** | G | 10 | 5 | (EPRI, 2010; Rubin et al., 2007) |
| | L | 20 | 10 | As above + (Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001) |
| **Gas peaking plant** | - | - | - | |
| **Gas combined cycle** | - | - | - | |
| **Nuclear** | G | - | 3 | (International Energy Agency, 2008) |
| **Diesel/oil-based generation** | - | - | - | |
| **Hydroelectric** | - | - | - | |
| **Biomass** | G | - | 5 | (International Energy Agency, 2008; Neij, 2008) |
| **Concentrating solar thermal** | G | 14.6 | 7 | (Hayward & Graham, 2013) |
| **Solar photovoltaics** | G | 20[18] | 10 | (Hayward & Graham, 2013; Wilson, 2012) |
| | L | - | 17.5 | As above |
| **Wind** | G | - | 4.3 | (Hayward & Graham, 2013) |
| | L | - | 11.3 | As above |

[18] We increase this learning rate to 35% for one doubling of capacity to accurately capture a period of faster learning

| Technology | Component | LR 1 (%) | LR 2 (%) | Reference |
|---|---|---|---|---|
| **Wave** | G | - | 9 | (Hayward & Graham, 2013) |
| **Tidal/ocean current** | G | - | 9 | (Hayward & Graham, 2013) |
| **CHP** | - | - | - | |
| **Enhanced geothermal** | G | - | 20 | (Grübler et al., 1999; Hayward & Graham, 2013; Schrattenholzer & McDonald, 2001) |
| | G | - | 8 | As above |
| | L | 20 | 20 | As above |
| **Conventional geothermal** | G | - | 8 | As above |
| | L | 20 | 20 | As above |
| **Fuel cells** | G | - | 20 | (Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010) |
| **Utility scale energy storage – li-ion** | G | - | 15 | (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015) |
| | L | - | 7.5 | |
| **Utility scale energy storage – flow batteries** | G | - | 15 | (Brinsmead et al., 2015) |
| | L | - | 7.5 | |
| **Pumped hydro** | G | - | | |
| | L | - | 20 | (Grübler et al., 1999; Schrattenholzer & McDonald, 2001) |

**Pf=pulverised fuel, IGCC=integrated gasification combined cycle, CHP=combined heat and power**

Solar photovoltaics is listed as one technology with global and local components in Apx Table A.1 however there are three separate PV plant technologies in GALLME:

- Rooftop PV includes solar photovoltaic modules and the local learning component is the balance of plant (BOP).
- Large scale PV also include modules and BOP. However, a discount of 25% is given to the BOP to take into account economies of scale in building a large scale versus rooftop PV plant.
- PV with storage has all of the components including batteries.

Inverters are not given a learning rate instead they are given a constant cost reduction, which is based on historical data.

Li-ion batteries are a component that is used in both PV with storage and utility scale Li-ion battery energy storage. Geothermal BOP includes the power generation and is a component shared among both types of geothermal plant in Apx Table A.1. Installation BOP is a component of utility scale battery storage that is shared between both types of utility scale battery storage.

Shared technology components mean that when one of the technologies that uses that component is installed, the costs decrease not just for that technology but for all technologies that use that component.

### A.1.4 Mature technologies and the "basket of costs"

There are three main drivers of mature technology costs: imported materials and equipment, domestic materials and equipment, and labour. The indices of these drivers over the last 20 years (ABS data) combined with the split in capital cost of mature technologies between imported equipment, domestic equipment and labour (Bureau of Resource and Energy Economics (BREE), 2012) was used to calculate an average rate of change in technology costs: - 0.012%. This value has been applied as an annual capital cost reduction factor to mature technologies and to operating and maintenance costs.

### A.1.5 GALLME assumptions

#### Government policies

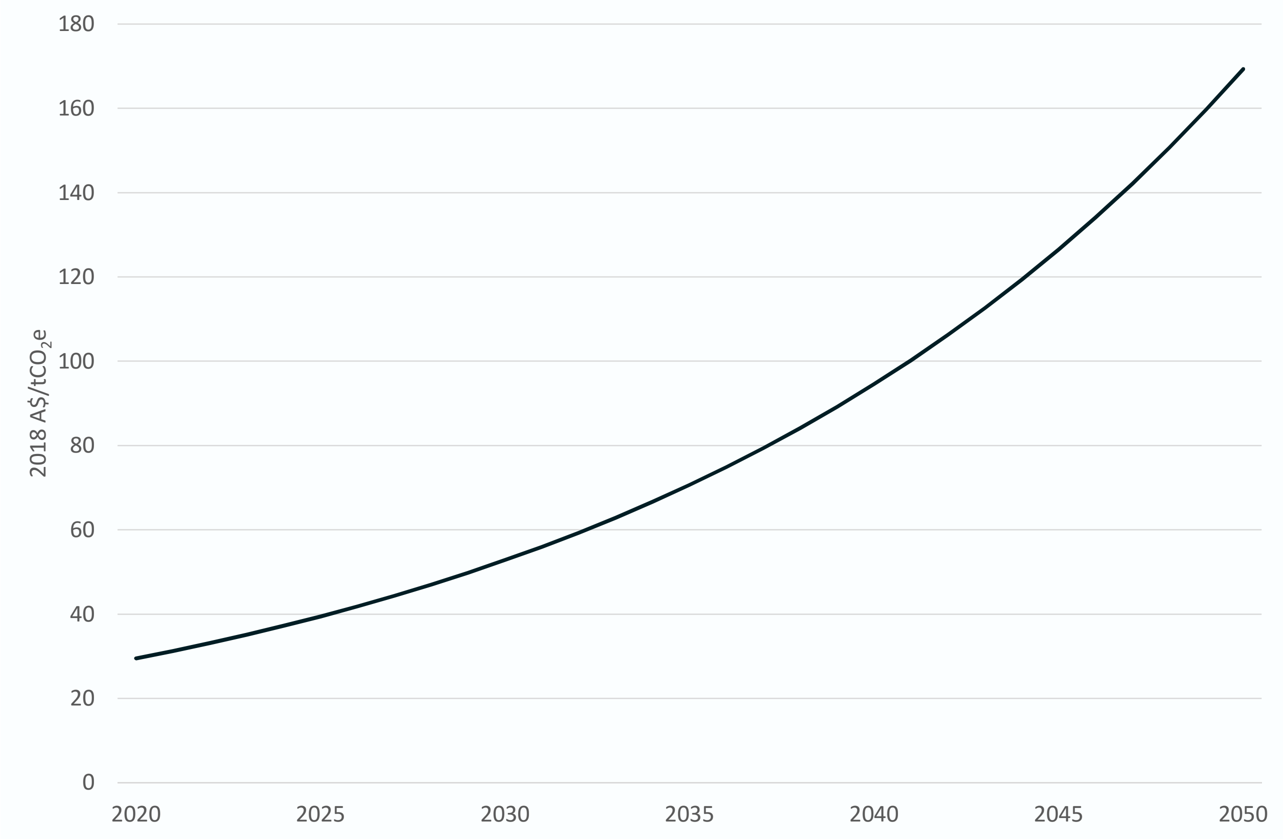
GALLME contains government policies which act as incentives for technologies to reduce costs or limits their uptake. The key assumption about government policy that has an impact on results is a carbon price. The carbon prices assumed in the 2-degree and 4-degree scenario are based on Clarke et al. (2014) and are shown in Apx Figure A.2 and Apx Figure A.3 respectively.

#### Resource constraints

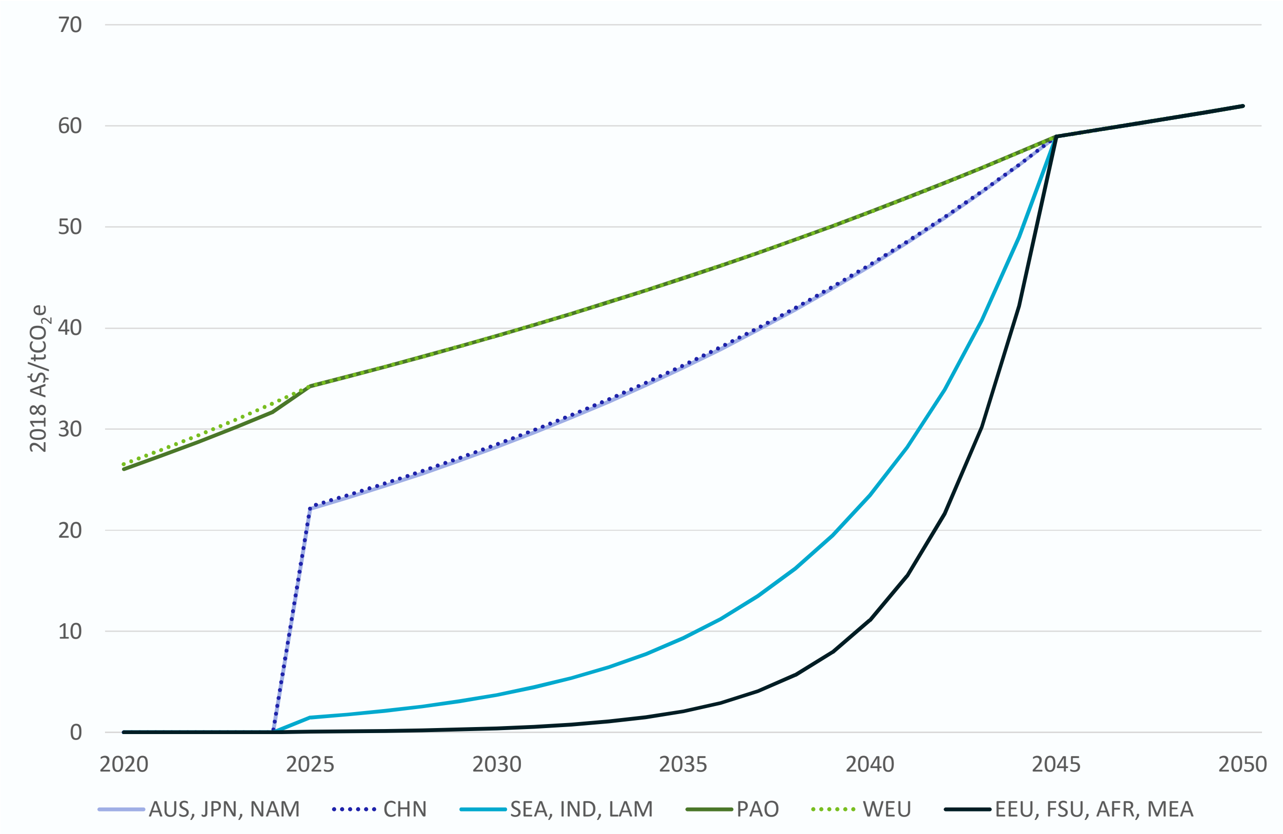
Constraints around the availability of suitable sites for renewable energy farms, available rooftop space for rooftop PV and sites for storage of $CO_2$ generated from using CCS have been included in GALLME as a constraint on the amount of electricity that can be generated from these technologies (Government of India, 2016) (Edmonds, et al., 2013). See (Hayward & Graham, 2017) for more information.

#### Exogenous data assumptions

GALLME obtains demand for electricity and international fossil fuel prices from (IEA, 2017). Australian fossil fuel prices are from GHD (2018). Power plant technology operating and maintenance (O&M) costs, plant efficiencies and fossil fuel emission factors were obtained from (IEA, 2016) (IEA, 2015), capacity factors from (IRENA, 2015) (IEA, 2015) (CO2CRC, 2015) and historical technology installed capacities from (IEA , 2008) (Gas Turbine World, 2009) (Gas Turbine World, 2010) (Gas Turbine World, 2011) (Gas Turbine World, 2012) (Gas Turbine World, 2013) (UN, 2015) (UN, 2015) (US Energy Information Administration, 2017) (US Energy Information Administration, 2017) (GWEC) (IEA) (IEA, 2016) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015 ).




Apx Figure A.1: Assumed 2-degrees carbon prices, all regions

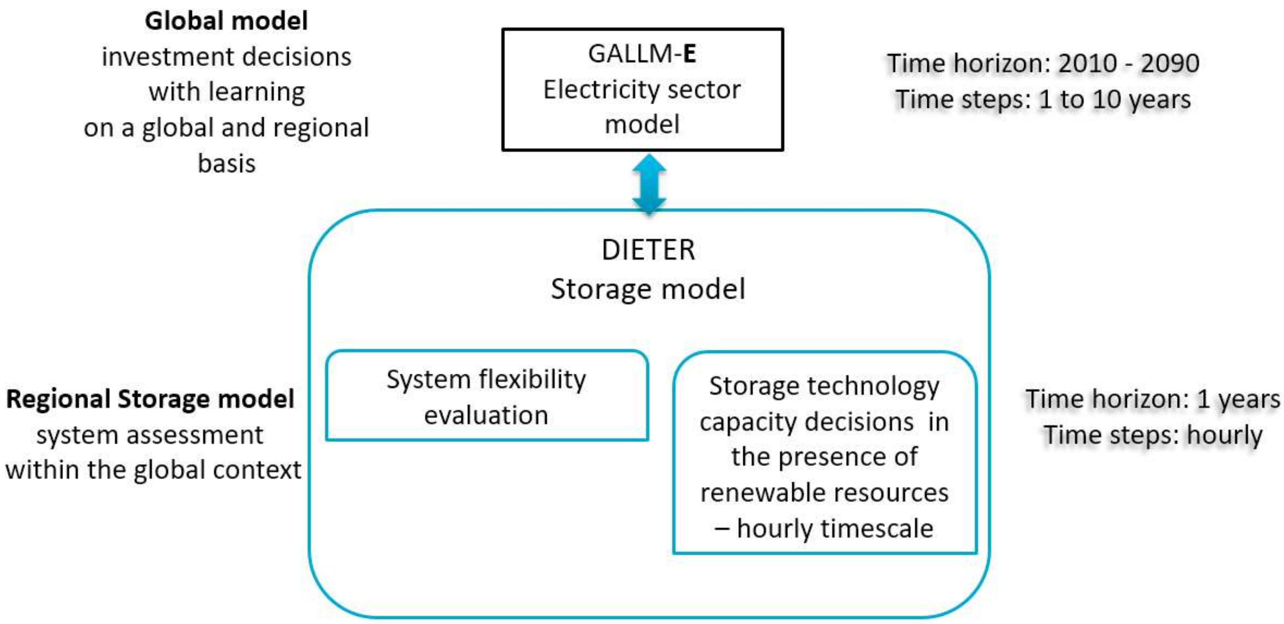



Apx Figure A.2: Assumed 4-degrees carbon prices by region

### A.1.6 Variable Renewables and Energy Storage

The Dispatch and Investment Evaluation Tool with Endogenous Renewables (DIETER) is an open source model which has been designed to model the cost of electricity generation systems with high shares of variable renewables (PV, wind and ocean renewables) and energy storage (http://www.diw.de/dieter). DIETER contains hourly renewable resource and load data for one calendar year, and because of this granularity, it is better able to optimise variable renewable and storage combinations than GALLME in any one year.

DIETER has been used in this study to determine the new capacity of variable renewables and storage technologies in the years that DIETER is solved and this data has then been included back in GALLME to update the cumulative capacity and thus the capital cost of these technologies. A schematic of the interaction between GALLME and DIETER is shown in Apx Figure A.4.




Apx Figure A.3: Schematic diagram of GALLM and DIETER modelling framework

The model interactions are as follows:

1. GALLME is solved without DIETER to calculate cost and uptake of all technologies
2. GALLME cost data, installed capacity of non-variable renewable technologies and upper and lower bounds on demand for electricity satisfied by variable renewables are used as inputs into DIETER
3. DIETER is solved for each region in 5-yearly intervals, beginning in 2025.
4. The new installed capacity of variable renewables and storage is included in GALLME and GALLME is solved.

# Appendix B Data tables

The following tables provide data behind some of the figures presented in this document.

## Apx Table B.1: Capital cost projections under 4 degree scenario

| | Black coal | Black coal with CCS | Brown coal | Brown coal with CCS | Gas combined cycle | Gas peak | Gas with CCS | Biomass | Biomass with CCS | Large scale solar PV | Rooftop solar panels | Solar thermal (8 hrs) | Wind | Wave | Enhanced geothermal | Nuclear (SMR) | Tidal/ocean current | Fuel cell | Battery storage (2 hrs) | Battery storage BOP | Integrated solar and battery (2 hrs) | PHES (6 hrs) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kWh | $/kWh | $/kW | $/kW |
| **2018** | 3257 | 6009 | 5027 | 9223 | 1278 | 894 | 3783 | 12595 | 11898 | 1574 | 1800 | 7011 | 2018 | 9107 | 14000 | 16000 | 6765 | 2320 | 274 | 527 | 3495 | 1200 |
| **2019** | 3252 | 6002 | 5019 | 9212 | 1276 | 893 | 3781 | 12567 | 11883 | 1458 | 1667 | 5814 | 1997 | 9107 | 14139 | 16000 | 6652 | 2139 | 224 | 520 | 3135 | 1198 |
| **2020** | 3247 | 5995 | 5011 | 9201 | 1274 | 891 | 3778 | 12523 | 11869 | 1349 | 1543 | 5216 | 1982 | 9107 | 14267 | 16000 | 6282 | 1908 | 200 | 501 | 2875 | 1197 |
| **2021** | 3242 | 5988 | 5003 | 9189 | 1272 | 890 | 3776 | 12518 | 11854 | 1175 | 1344 | 5216 | 1968 | 9107 | 14353 | 15987 | 5639 | 1717 | 193 | 485 | 2577 | 1195 |
| **2022** | 3236 | 5981 | 4995 | 9178 | 1270 | 889 | 3774 | 12507 | 11839 | 1118 | 1278 | 5216 | 1958 | 9107 | 14431 | 15969 | 5344 | 1566 | 177 | 472 | 2451 | 1193 |
| **2023** | 3231 | 5974 | 4987 | 9166 | 1268 | 887 | 3772 | 12507 | 11825 | 1068 | 1222 | 5216 | 1950 | 9107 | 14517 | 15969 | 5342 | 1474 | 161 | 462 | 2342 | 1192 |
| **2024** | 3226 | 5968 | 4979 | 9155 | 1266 | 886 | 3769 | 12507 | 11810 | 1029 | 1176 | 5216 | 1942 | 9107 | 14494 | 15969 | 5340 | 1414 | 145 | 449 | 2189 | 1190 |
| **2025** | 3221 | 5961 | 4971 | 9144 | 1264 | 884 | 3767 | 12507 | 11796 | 990 | 1131 | 5216 | 1936 | 9107 | 14474 | 15969 | 5336 | 1374 | 129 | 432 | 2021 | 1189 |
| **2026** | 3216 | 5954 | 4963 | 9132 | 1262 | 883 | 3765 | 12507 | 11781 | 957 | 1094 | 5216 | 1930 | 9107 | 14453 | 15969 | 5332 | 1347 | 103 | 432 | 1876 | 1187 |
| **2027** | 3211 | 5947 | 4955 | 9121 | 1260 | 881 | 3762 | 12507 | 11766 | 926 | 1059 | 5216 | 1927 | 9107 | 14453 | 15966 | 5327 | 1328 | 84 | 432 | 1758 | 1185 |
| **2028** | 3205 | 5940 | 4947 | 9110 | 1258 | 880 | 3760 | 12507 | 11752 | 891 | 1019 | 5216 | 1924 | 9107 | 14453 | 15963 | 5320 | 1313 | 72 | 432 | 1654 | 1184 |
| **2029** | 3200 | 5934 | 4939 | 9099 | 1256 | 879 | 3758 | 12507 | 11737 | 860 | 983 | 5216 | 1921 | 9107 | 14423 | 15954 | 5311 | 1301 | 64 | 432 | 1572 | 1182 |
| **2030** | 3195 | 5927 | 4932 | 9087 | 1254 | 877 | 3756 | 12507 | 11723 | 832 | 951 | 5207 | 1918 | 6955 | 14423 | 15949 | 5301 | 1292 | 47 | 432 | 1466 | 1180 |
| **2031** | 3190 | 5920 | 4924 | 9076 | 1252 | 876 | 3753 | 12505 | 11708 | 806 | 922 | 5200 | 1915 | 6139 | 14401 | 15860 | 5288 | 1279 | 46 | 432 | 1416 | 1179 |
| **2032** | 3185 | 5913 | 4916 | 9065 | 1250 | 874 | 3751 | 12505 | 11694 | 792 | 905 | 5159 | 1911 | 5285 | 14398 | 15855 | 5288 | 1243 | 46 | 432 | 1392 | 1177 |
| **2033** | 3180 | 5907 | 4908 | 9054 | 1248 | 873 | 3749 | 12504 | 11680 | 774 | 885 | 5123 | 1894 | 4941 | 14394 | 15850 | 5288 | 1104 | 46 | 432 | 1364 | 1176 |
| **2034** | 3175 | 5900 | 4900 | 9043 | 1246 | 872 | 3747 | 12504 | 11665 | 755 | 863 | 4674 | 1870 | 4234 | 14388 | 15847 | 5288 | 1072 | 45 | 432 | 1334 | 1174 |
| **2035** | 3170 | 5893 | 4892 | 9032 | 1244 | 870 | 3744 | 12502 | 11651 | 749 | 856 | 4502 | 1867 | 4162 | 14379 | 15845 | 5288 | 1044 | 45 | 432 | 1323 | 1172 |
| **2036** | 3165 | 5880 | 4884 | 9012 | 1242 | 869 | 3733 | 12501 | 11626 | 721 | 824 | 4411 | 1864 | 3851 | 14379 | 15844 | 5281 | 1026 | 45 | 432 | 1281 | 1171 |
| **2037** | 3160 | 5696 | 4877 | 8785 | 1240 | 867 | 3487 | 12501 | 11333 | 712 | 814 | 4232 | 1861 | 3740 | 14368 | 15844 | 5281 | 1008 | 44 | 432 | 1266 | 1169 |
| **2038** | 3154 | 5617 | 4869 | 8685 | 1238 | 866 | 3384 | 12501 | 11204 | 703 | 804 | 4111 | 1858 | 3706 | 14368 | 15844 | 5278 | 931 | 44 | 432 | 1252 | 1168 |
| **2039** | 3149 | 5518 | 4861 | 8562 | 1236 | 865 | 3255 | 12501 | 11045 | 697 | 797 | 4023 | 1855 | 3677 | 14368 | 15844 | 5278 | 892 | 44 | 427 | 1241 | 1166 |
| **2040** | 3144 | 5425 | 4853 | 8445 | 1234 | 863 | 3133 | 12499 | 10895 | 688 | 787 | 3957 | 1851 | 3156 | 14366 | 15844 | 5265 | 846 | 44 | 419 | 1227 | 1164 |
| **2041** | 3139 | 5336 | 4845 | 8334 | 1232 | 862 | 3017 | 12493 | 10751 | 667 | 762 | 3905 | 1848 | 2945 | 14354 | 15844 | 5233 | 802 | 44 | 419 | 1197 | 1163 |
| **2042** | 3134 | 5302 | 4838 | 8289 | 1230 | 861 | 2977 | 12493 | 10693 | 647 | 739 | 3864 | 1845 | 2909 | 14354 | 15831 | 5189 | 776 | 43 | 419 | 1168 | 1161 |
| **2043** | 3129 | 5293 | 4830 | 8275 | 1228 | 859 | 2971 | 12493 | 10675 | 629 | 719 | 3830 | 1843 | 2850 | 14342 | 15827 | 5158 | 770 | 43 | 419 | 1142 | 1160 |
| **2044** | 3124 | 5276 | 4822 | 8252 | 1226 | 858 | 2955 | 12493 | 10645 | 611 | 698 | 3802 | 1840 | 2800 | 13800 | 15824 | 5135 | 765 | 43 | 419 | 1116 | 1158 |
| **2045** | 3119 | 5265 | 4814 | 8235 | 1224 | 856 | 2946 | 12493 | 10623 | 594 | 679 | 3778 | 1838 | 2800 | 13699 | 15824 | 5045 | 761 | 43 | 419 | 1092 | 1156 |
| **2046** | 3114 | 5254 | 4807 | 8219 | 1222 | 855 | 2939 | 12493 | 10603 | 578 | 661 | 3757 | 1836 | 2781 | 13624 | 15824 | 4965 | 755 | 43 | 419 | 1068 | 1155 |
| **2047** | 3109 | 5246 | 4799 | 8207 | 1220 | 854 | 2935 | 12445 | 10587 | 570 | 652 | 3705 | 1833 | 2781 | 13578 | 15824 | 4906 | 752 | 43 | 419 | 1056 | 1153 |
| **2048** | 3104 | 5239 | 4791 | 8195 | 1218 | 852 | 2932 | 12368 | 10572 | 560 | 640 | 3642 | 1829 | 2751 | 13569 | 15824 | 4906 | 749 | 43 | 419 | 1041 | 1152 |
| **2049** | 3099 | 5232 | 4784 | 8184 | 1216 | 851 | 2929 | 12341 | 10557 | 546 | 625 | 3586 | 1825 | 2751 | 13552 | 15823 | 4905 | 746 | 43 | 419 | 1021 | 1150 |
| **2050** | 3094 | 5224 | 4776 | 8171 | 1214 | 850 | 2924 | 12265 | 10540 | 543 | 621 | 3537 | 1820 | 2688 | 13461 | 15823 | 4772 | 746 | 43 | 419 | 1016 | 1149 |

Notes: Battery storage is for large scale plant. In Hayward and Graham (2017) biomass and nuclear were large scale. Here they are small scale. Integrated solar and battery is residential. Battery storage (2hrs) and battery balance of plant (BOP) must be added for full cost of battery storage. The battery storage BOP is for large scale, and not relevant for integrated solar and battery.

## Apx Table B.2: Capital cost projections under 2 degree scenario

| | Black coal | Black coal with CCS | Brown coal | Brown coal with CCS | Gas combined cycle | Gas peak | Gas with CCS | Biomass | Biomass with CCS | Large scale solar PV | Rooftop solar panels | Solar thermal (8 hrs) | Wind | Wave | Enhanced geothermal | Nuclear (SMR) | Tidal/ocean current | Fuel cell | Battery storage (2 hrs) | Battery storage BOP | Integrated solar and battery (2 hrs) | PHES (6 hrs) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kWh | $/kWh | $/kW | $/kW |
| **2018** | 3257 | 6009 | 5027 | 9223 | 1278 | 894 | 3783 | 12595 | 11898 | 1574 | 1800 | 7011 | 2018 | 9107 | 14000 | 16000 | 6765 | 2320 | 274 | 527 | 3495 | 1200 |
| **2019** | 3252 | 6002 | 5019 | 9212 | 1276 | 893 | 3781 | 12595 | 11883 | 1450 | 1656 | 5993 | 2009 | 9107 | 14056 | 15992 | 5998 | 2139 | 228 | 508 | 3136 | 1198 |
| **2020** | 3247 | 5995 | 5011 | 9201 | 1274 | 891 | 3778 | 12592 | 11869 | 1280 | 1470 | 5377 | 2005 | 9107 | 14168 | 15991 | 5998 | 1908 | 203 | 493 | 2792 | 1197 |
| **2021** | 3242 | 5988 | 5003 | 9189 | 1272 | 890 | 3776 | 12587 | 11854 | 1218 | 1398 | 5377 | 1998 | 9107 | 14245 | 15989 | 5601 | 1717 | 197 | 483 | 2649 | 1195 |
| **2022** | 3236 | 5981 | 4995 | 9178 | 1270 | 889 | 3774 | 12576 | 11839 | 1170 | 1345 | 5377 | 1991 | 9107 | 14332 | 15971 | 5565 | 1566 | 184 | 476 | 2546 | 1193 |
| **2023** | 3231 | 5974 | 4987 | 9166 | 1268 | 887 | 3772 | 12576 | 11825 | 1122 | 1291 | 5377 | 1984 | 9107 | 14410 | 15971 | 5562 | 1474 | 170 | 471 | 2444 | 1192 |
| **2024** | 3226 | 5968 | 4979 | 9155 | 1266 | 886 | 3769 | 12576 | 11810 | 1081 | 1245 | 5377 | 1954 | 9107 | 14393 | 15971 | 5560 | 1414 | 156 | 466 | 2352 | 1190 |
| **2025** | 3221 | 5961 | 4971 | 9144 | 1264 | 884 | 3767 | 12576 | 11796 | 986 | 1142 | 5377 | 1940 | 9107 | 14381 | 15971 | 5556 | 1374 | 142 | 463 | 2057 | 1189 |
| **2026** | 3216 | 5954 | 4963 | 9132 | 1262 | 883 | 3765 | 12576 | 11781 | 903 | 1051 | 5377 | 1922 | 9107 | 14376 | 15968 | 5552 | 1347 | 111 | 462 | 1830 | 1187 |
| **2027** | 3211 | 5947 | 4955 | 9121 | 1260 | 881 | 3762 | 12576 | 11766 | 877 | 1020 | 5370 | 1909 | 9107 | 14376 | 15966 | 5546 | 1328 | 89 | 462 | 1708 | 1185 |
| **2028** | 3205 | 5940 | 4947 | 9110 | 1258 | 880 | 3760 | 12576 | 11752 | 853 | 992 | 5355 | 1895 | 9107 | 14376 | 15963 | 5539 | 1313 | 75 | 461 | 1616 | 1184 |
| **2029** | 3200 | 5779 | 4939 | 8910 | 1256 | 879 | 3544 | 12547 | 11494 | 830 | 965 | 5328 | 1892 | 9107 | 14376 | 15956 | 5530 | 1301 | 68 | 461 | 1546 | 1182 |
| **2030** | 3195 | 5705 | 4932 | 8817 | 1254 | 877 | 3450 | 12432 | 11374 | 817 | 949 | 5281 | 1874 | 9107 | 14376 | 15953 | 5519 | 1292 | 49 | 460 | 1457 | 1180 |
| **2031** | 3190 | 5598 | 4924 | 8683 | 1252 | 876 | 3308 | 12427 | 11201 | 791 | 919 | 5281 | 1866 | 9107 | 14376 | 15868 | 5506 | 1187 | 48 | 460 | 1405 | 1179 |
| **2032** | 3185 | 5498 | 4916 | 8558 | 1250 | 874 | 3178 | 12427 | 11040 | 781 | 906 | 5281 | 1857 | 9107 | 14373 | 15843 | 5506 | 1147 | 48 | 459 | 1388 | 1177 |
| **2033** | 3180 | 5461 | 4908 | 8509 | 1248 | 873 | 3133 | 12427 | 10977 | 769 | 891 | 5280 | 1849 | 7648 | 14368 | 15843 | 5506 | 1070 | 48 | 457 | 1367 | 1176 |
| **2034** | 3175 | 5427 | 4900 | 8465 | 1246 | 872 | 3094 | 12427 | 10920 | 753 | 872 | 5266 | 1839 | 6396 | 14362 | 15843 | 5506 | 1048 | 47 | 456 | 1342 | 1174 |
| **2035** | 3170 | 5399 | 4892 | 8429 | 1244 | 870 | 3063 | 12424 | 10873 | 746 | 863 | 5104 | 1830 | 5610 | 14352 | 15843 | 5506 | 1030 | 47 | 455 | 1329 | 1172 |
| **2036** | 3165 | 5370 | 4884 | 8390 | 1242 | 869 | 3030 | 12395 | 10824 | 728 | 842 | 4878 | 1823 | 5083 | 14347 | 15843 | 5498 | 1022 | 47 | 454 | 1301 | 1171 |
| **2037** | 3160 | 5353 | 4877 | 8367 | 1240 | 867 | 3013 | 12261 | 10793 | 725 | 838 | 4653 | 1820 | 4533 | 14344 | 15843 | 5496 | 1007 | 46 | 453 | 1294 | 1169 |
| **2038** | 3154 | 5334 | 4869 | 8341 | 1238 | 866 | 2994 | 12249 | 10759 | 715 | 826 | 4547 | 1815 | 4030 | 14341 | 15843 | 5496 | 945 | 46 | 452 | 1278 | 1168 |
| **2039** | 3149 | 5314 | 4861 | 8313 | 1236 | 865 | 2973 | 12249 | 10723 | 710 | 820 | 4348 | 1813 | 3791 | 14341 | 15843 | 5496 | 912 | 46 | 452 | 1269 | 1166 |
| **2040** | 3144 | 5299 | 4853 | 8291 | 1234 | 863 | 2959 | 12082 | 10696 | 699 | 807 | 4218 | 1808 | 3278 | 13749 | 15843 | 5475 | 873 | 45 | 451 | 1252 | 1164 |
| **2041** | 3139 | 5289 | 4845 | 8276 | 1232 | 862 | 2952 | 11909 | 10676 | 688 | 794 | 4126 | 1798 | 3249 | 13704 | 15842 | 5439 | 831 | 45 | 451 | 1234 | 1163 |
| **2042** | 3134 | 5282 | 4838 | 8264 | 1230 | 861 | 2949 | 11895 | 10661 | 682 | 787 | 4058 | 1796 | 3158 | 13702 | 15823 | 5383 | 791 | 45 | 451 | 1225 | 1161 |
| **2043** | 3129 | 5274 | 4830 | 8253 | 1228 | 859 | 2946 | 11895 | 10646 | 665 | 768 | 4005 | 1794 | 3158 | 13702 | 15823 | 5308 | 784 | 45 | 451 | 1200 | 1160 |
| **2044** | 3124 | 5267 | 4822 | 8241 | 1226 | 858 | 2943 | 11872 | 10631 | 645 | 746 | 3964 | 1785 | 3080 | 13697 | 15823 | 5189 | 781 | 45 | 451 | 1171 | 1158 |
| **2045** | 3119 | 5260 | 4814 | 8229 | 1224 | 856 | 2940 | 11872 | 10616 | 632 | 730 | 3930 | 1782 | 3080 | 13687 | 15823 | 5189 | 779 | 45 | 450 | 1151 | 1156 |
| **2046** | 3114 | 5252 | 4807 | 8217 | 1222 | 855 | 2936 | 11868 | 10599 | 608 | 704 | 3902 | 1779 | 3080 | 13687 | 15823 | 5117 | 767 | 45 | 450 | 1117 | 1155 |
| **2047** | 3109 | 5245 | 4799 | 8205 | 1220 | 854 | 2933 | 11868 | 10585 | 605 | 700 | 3878 | 1775 | 3080 | 13649 | 15823 | 5108 | 766 | 45 | 450 | 1112 | 1153 |
| **2048** | 3104 | 5238 | 4791 | 8193 | 1218 | 852 | 2930 | 11864 | 10569 | 593 | 687 | 3834 | 1770 | 3080 | 13588 | 15823 | 5108 | 760 | 44 | 449 | 1094 | 1152 |
| **2049** | 3099 | 5230 | 4784 | 8182 | 1216 | 851 | 2927 | 11864 | 10554 | 582 | 674 | 3763 | 1766 | 2967 | 13523 | 15823 | 5107 | 757 | 44 | 449 | 1077 | 1150 |
| **2050** | 3094 | 5222 | 4776 | 8169 | 1214 | 850 | 2923 | 11864 | 10538 | 579 | 671 | 3701 | 1759 | 2965 | 13435 | 15823 | 4962 | 753 | 44 | 449 | 1073 | 1149 |

Notes: Battery storage is for large scale plant. In Hayward and Graham (2017) biomass and nuclear were large scale. Here they are small scale. Integrated solar and battery is residential. Battery storage (2hrs) and battery balance of plant (BOP) must be added for full cost of battery storage. The battery storage BOP is for large scale, and not relevant for integrated solar and battery.

### Apx Table B.3: Data assumptions for LCOE calculations

| | Constant | | | | | | Low assumption | | | | | High assumption | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Life | Construction time | Efficiency | O&M fixed | O&M variable | $CO_2$ storage | Capital | Fuel | Capacity factor | Emission factor | Carbon price | Capital | Fuel | Capacity factor | Emission factor | Carbon price |
| | Years | Years | | $/kW | $/MWh | $/MWh | $/kW | $/GJ | | $ktCO_2e$/PJ | $/$tCO_2e$ | $/kW | $/GJ | | $ktCO_2e$/PJ | $/$tCO_2e$ |
| **2020** | | | | | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 2.0 | 41% | 17.9 | 12.6 | 1.9 | 3778 | 5.8 | 80% | 6.4 | 16.9 | 3778 | 11.3 | 60% | 19.9 | 28.7 |
| **Gas combined cycle** | 25 | 2.0 | 48% | 10.5 | 7.4 | 0.0 | 1274 | 5.8 | 80% | 52.1 | 16.9 | 1274 | 11.3 | 60% | 65.6 | 28.7 |
| **Gas peaking** | 25 | 1.0 | 31% | 4.2 | 10.5 | 0.0 | 891 | 5.8 | 20% | 53.1 | 16.9 | 891 | 11.3 | 20% | 66.6 | 28.7 |
| **Black coal with CCS** | 25 | 4.0 | 30% | 77.1 | 9.5 | 4.1 | 5995 | 2.8 | 80% | 8.5 | 16.9 | 5995 | 4.1 | 60% | 15.4 | 28.7 |
| **Black coal** | 25 | 4.0 | 40% | 53.2 | 4.2 | 0.0 | 3247 | 2.8 | 80% | 88.0 | 16.9 | 3247 | 4.1 | 60% | 88.0 | 28.7 |
| **Brown coal with CCS** | 25 | 4.0 | 21% | 101.6 | 11.6 | 4.7 | 9201 | 0.6 | 80% | 5.8 | 16.9 | 9201 | 0.7 | 60% | 5.8 | 28.7 |
| **Brown coal** | 25 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 5011 | 0.6 | 80% | 85.0 | 16.9 | 5011 | 0.7 | 60% | 85.0 | 28.7 |
| **Biomass (small scale)** | 25 | 2.0 | 23% | 131.6 | 8.4 | 0.0 | 12523 | 0.5 | 60% | 0.0 | 16.9 | 12592 | 2.0 | 40% | 0.0 | 28.7 |
| **Nuclear (SMR)** | 60 | 5.0 | 45% | 200.0 | 20.0 | 0.0 | 16000 | 0.0 | 80% | 0.0 | 16.9 | 15991 | 0.0 | 60% | 0.0 | 28.7 |
| **Large scale solar PV** | 25 | 1.0 | 100% | 14.4 | 0.0 | 0.0 | 1349 | 0.0 | 32% | 0.0 | 16.9 | 1280 | 0.0 | 22% | 0.0 | 28.7 |
| **Solar thermal (8hrs)** | 25 | 2.4 | 100% | 85.0 | 5.4 | 0.0 | 5216 | 0.0 | 52% | 0.0 | 16.9 | 5377 | 0.0 | 42% | 0.0 | 28.7 |
| **Wind** | 25 | 1.2 | 100% | 36.0 | 2.7 | 0.0 | 1982 | 0.0 | 44% | 0.0 | 16.9 | 2005 | 0.0 | 35% | 0.0 | 28.7 |
| **Fuel cell** | 10 | 1.0 | 55% | 38.2 | 0.0 | 0.0 | 1908 | 20.8 | 20% | 0.0 | 16.9 | 1908 | 30.0 | 20% | 0.0 | 28.7 |
| **2030** | | | | | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 2.0 | 41% | 17.9 | 12.6 | 1.9 | 3756 | 5.8 | 80% | 6.4 | 27.5 | 3450 | 11.8 | 60% | 19.9 | 50.1 |
| **Gas combined cycle** | 25 | 2.0 | 48% | 10.5 | 7.4 | 0.0 | 1254 | 5.8 | 80% | 52.1 | 27.5 | 1254 | 11.8 | 60% | 65.6 | 50.1 |
| **Gas peaking** | 25 | 1.0 | 31% | 4.2 | 10.5 | 0.0 | 877 | 5.8 | 20% | 53.1 | 27.5 | 877 | 11.8 | 20% | 66.6 | 50.1 |
| **Black coal with CCS** | 25 | 4.0 | 30% | 77.1 | 9.5 | 4.1 | 5927 | 2.9 | 80% | 8.5 | 27.5 | 5705 | 3.8 | 60% | 15.4 | 50.1 |
| **Black coal** | 25 | 4.0 | 40% | 53.2 | 4.2 | 0.0 | 3195 | 2.9 | 80% | 88.0 | 27.5 | 3195 | 3.8 | 60% | 88.0 | 50.1 |
| **Brown coal with CCS** | 25 | 4.0 | 21% | 101.6 | 11.6 | 4.7 | 9087 | 0.7 | 80% | 5.8 | 27.5 | 8817 | 0.7 | 60% | 5.8 | 50.1 |
| **Brown coal** | 25 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 4932 | 0.7 | 80% | 85.0 | 27.5 | 4932 | 0.7 | 60% | 85.0 | 50.1 |
| **Biomass (small scale)** | 25 | 2.0 | 23% | 131.6 | 8.4 | 0.0 | 12507 | 0.5 | 60% | 0.0 | 27.5 | 12432 | 2.0 | 40% | 0.0 | 50.1 |
| **Nuclear (SMR)** | 60 | 5.0 | 45% | 200.0 | 20.0 | 0.0 | 15949 | 0.0 | 80% | 0.0 | 27.5 | 15953 | 0.0 | 60% | 0.0 | 50.1 |
| **Large scale solar PV** | 25 | 1.0 | 100% | 14.4 | 0.0 | 0.0 | 832 | 0.0 | 32% | 0.0 | 27.5 | 817 | 0.0 | 19% | 0.0 | 50.1 |
| **Solar thermal (8hrs)** | 25 | 2.4 | 100% | 85.0 | 5.4 | 0.0 | 5207 | 0.0 | 52% | 0.0 | 27.5 | 5281 | 0.0 | 42% | 0.0 | 50.1 |
| **Wind** | 25 | 1.2 | 100% | 36.0 | 2.7 | 0.0 | 1918 | 0.0 | 46% | 0.0 | 27.5 | 1874 | 0.0 | 35% | 0.0 | 50.1 |
| **Fuel cell** | 10 | 1.0 | 60% | 25.8 | 0.0 | 0.0 | 1292 | 20.8 | 20% | 0.0 | 27.5 | 1292 | 30.0 | 20% | 0.0 | 50.1 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2040** | | | | | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 2.0 | 41% | 17.9 | 12.6 | 1.9 | 3133 | 5.8 | 80% | 6.4 | 44.9 | 2959 | 11.8 | 60% | 19.9 | 85.7 |
| **Gas combined cycle** | 25 | 2.0 | 48% | 10.5 | 7.4 | 0.0 | 1234 | 5.8 | 80% | 52.1 | 44.9 | 1234 | 11.8 | 60% | 65.6 | 85.7 |
| **Gas peaking** | 25 | 1.0 | 31% | 4.2 | 10.5 | 0.0 | 863 | 5.8 | 20% | 53.1 | 44.9 | 863 | 11.8 | 20% | 66.6 | 85.7 |
| **Black coal with CCS** | 25 | 4.0 | 30% | 77.1 | 9.5 | 4.1 | 5425 | 2.9 | 80% | 8.5 | 44.9 | 5299 | 3.8 | 60% | 15.4 | 85.7 |
| **Black coal** | 25 | 4.0 | 40% | 53.2 | 4.2 | 0.0 | 3144 | 2.9 | 80% | 88.0 | 44.9 | 3144 | 3.8 | 60% | 88.0 | 85.7 |
| **Brown coal with CCS** | 25 | 4.0 | 21% | 101.6 | 11.6 | 4.7 | 8445 | 0.7 | 80% | 5.8 | 44.9 | 8291 | 0.7 | 60% | 5.8 | 85.7 |
| **Brown coal** | 25 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 4853 | 0.7 | 80% | 85.0 | 44.9 | 4853 | 0.7 | 60% | 85.0 | 85.7 |
| **Biomass (small scale)** | 25 | 2.0 | 23% | 131.6 | 8.4 | 0.0 | 12499 | 0.5 | 60% | 0.0 | 44.9 | 12082 | 2.0 | 40% | 0.0 | 85.7 |
| **Nuclear (SMR)** | 60 | 5.0 | 45% | 200.0 | 20.0 | 0.0 | 15844 | 0.0 | 80% | 0.0 | 44.9 | 15843 | 0.0 | 60% | 0.0 | 85.7 |
| **Large scale solar PV** | 25 | 1.0 | 100% | 14.4 | 0.0 | 0.0 | 688 | 0.0 | 32% | 0.0 | 44.9 | 699 | 0.0 | 19% | 0.0 | 85.7 |
| **Solar thermal (8hrs)** | 25 | 2.4 | 100% | 85.0 | 5.4 | 0.0 | 3957 | 0.0 | 52% | 0.0 | 44.9 | 4218 | 0.0 | 42% | 0.0 | 85.7 |
| **Wind** | 25 | 1.2 | 100% | 36.0 | 2.7 | 0.0 | 1851 | 0.0 | 48% | 0.0 | 44.9 | 1808 | 0.0 | 35% | 0.0 | 85.7 |
| **Fuel cell** | 10 | 1.0 | 60% | 16.9 | 0.0 | 0.0 | 846 | 20.8 | 20% | 0.0 | 44.9 | 873 | 30.0 | 20% | 0.0 | 85.7 |
| **2050** | | | | | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 2.0 | 41% | 17.9 | 12.6 | 1.9 | 2924 | 5.8 | 80% | 6.4 | 60.3 | 2923 | 11.8 | 60% | 19.9 | 146.3 |
| **Gas combined cycle** | 25 | 2.0 | 48% | 10.5 | 7.4 | 0.0 | 1214 | 5.8 | 80% | 52.1 | 60.3 | 1214 | 11.8 | 60% | 65.6 | 146.3 |
| **Gas peaking** | 25 | 1.0 | 31% | 4.2 | 10.5 | 0.0 | 850 | 5.8 | 20% | 53.1 | 60.3 | 850 | 11.8 | 20% | 66.6 | 146.3 |
| **Black coal with CCS** | 25 | 4.0 | 30% | 77.1 | 9.5 | 4.1 | 5224 | 2.9 | 80% | 8.5 | 60.3 | 5222 | 3.8 | 60% | 15.4 | 146.3 |
| **Black coal** | 25 | 4.0 | 40% | 53.2 | 4.2 | 0.0 | 3094 | 2.9 | 80% | 88.0 | 60.3 | 3094 | 3.8 | 60% | 88.0 | 146.3 |
| **Brown coal with CCS** | 25 | 4.0 | 21% | 101.6 | 11.6 | 4.7 | 8171 | 0.7 | 80% | 5.8 | 60.3 | 8169 | 0.7 | 60% | 5.8 | 146.3 |
| **Brown coal** | 25 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 4776 | 0.7 | 80% | 85.0 | 60.3 | 4776 | 0.7 | 60% | 85.0 | 146.3 |
| **Biomass (small scale)** | 25 | 2.0 | 23% | 131.6 | 8.4 | 0.0 | 12265 | 0.5 | 60% | 0.0 | 60.3 | 11864 | 2.0 | 40% | 0.0 | 146.3 |
| **Nuclear (SMR)** | 60 | 5.0 | 45% | 200.0 | 20.0 | 0.0 | 15823 | 0.0 | 80% | 0.0 | 60.3 | 15823 | 0.0 | 60% | 0.0 | 146.3 |
| **Large scale solar PV** | 25 | 1.0 | 100% | 14.4 | 0.0 | 0.0 | 543 | 0.0 | 32% | 0.0 | 60.3 | 579 | 0.0 | 19% | 0.0 | 146.3 |
| **Solar thermal (8hrs)** | 25 | 2.4 | 100% | 85.0 | 5.4 | 0.0 | 3537 | 0.0 | 52% | 0.0 | 60.3 | 3701 | 0.0 | 42% | 0.0 | 146.3 |
| **Wind** | 25 | 1.2 | 100% | 36.0 | 2.7 | 0.0 | 1820 | 0.0 | 50% | 0.0 | 60.3 | 1759 | 0.0 | 35% | 0.0 | 146.3 |
| **Fuel cell** | 10 | 1.0 | 60% | 14.9 | 0.0 | 0.0 | 746 | 20.8 | 20% | 0.0 | 60.3 | 753 | 30.0 | 20% | 0.0 | 146.3 |

Notes: A weighted average cost of capital of 7% was applied unless otherwise stated.

Apx Table B.4: Storage cost data by source and cost basis

| Cost basis | Source | Technology | Units | Cost |
|---|---|---|---|---|
| **Component cost basis** | GHD 2018 | Battery | $/kW | 600 |
| | | | $/kWh | 300 |
| | | Compressed air | $/kW | 350 |
| | | | $/kWh | 32 |
| | Blakers et al. 2017 | PHES | $/kW | 800 |
| | | | $/kWh | 70 |
| **Total cost basis** | CSIRO 2017 | Battery (2hrs) | $/kW | 1480 |
| | | | $/kWh | 740 |
| | GHD modified | Battery (2hrs) | $/kW | 1700 |
| | | | $/kWh | 850 |
| | GHD 2018 | Battery (1hr) | $/kW | 1400 |
| | | | $/kWh | 1400 |
| | | Compressed air (48hrs) | $/kW | 2467 |
| | | | $/kWh | 51 |
| | | PHES (6hrs) | $/kW | 1200 |
| | | | $/kWh | - |
| | | PHES (150hrs) | $/kW | - |
| | | | $/kWh | 20 |
| | Blakers modified | PHES (6hrs) | $/kW | 1220 |
| | | | $/kWh | - |
| | | PHES (150hrs) | $/kW | - |
| | | | $/kWh | 75 |
| | Entura 2018 | PHES (6hrs) | $/kW | 1480 |
| | | | $/kWh | 249 |
| | | PHES (48hrs) | $/kW | 2750 |
| | | | $/kWh | 57 |

# Shortened forms

| Abbreviation | Meaning |
|---|---|
| **ABS** | Australian Bureau of Statistics |
| **AEMC** | Australian Energy Market Commission |
| **AEMO** | Australian Electricity Market Operator |
| **AER** | Australian Energy Regulator |
| **AETA** | Australian Energy Technology Assessment |
| **APGT** | Australian Power Generation Technology report |
| **ARENA** | Australian Renewable Energy Agency |
| **BECCS** | Bioenergy with carbon capture and storage |
| **BOP** | Balance of plant |
| **BREE** | Bureau of Resource and Energy Economics |
| **CCS** | Carbon capture and storage |
| **CHP** | Combined heat and power |
| **$CO_2$** | Carbon dioxide |
| **CSIRO** | Commonwealth Scientific and Industrial Research Organisation |
| **CSP** | Concentrated solar power |
| **DEE** | Department of Environment and Energy |
| **DIETER** | Dispatch and investment evaluation tool with endogenous renewables |
| **DIIS** | Department of Industry, Innovation and Science |
| **DR** | Demand response |
| **DRM** | Demand response modes |
| **EPRI** | Electric Power Research Institute |

| | |
|---|---|
| **EUDM** | Energy Use Data Model |
| **GALLME** | Global and Local Learning Model Electricity |
| **GALLMs** | Global and Local Learning Models |
| **GALLMT** | Global and Local Learning Model Transport |
| **GW** | Gigawatt |
| **GWYr** | Gigawatt Years |
| **hrs** | Hours |
| **IEA** | International Energy Agency |
| **IGCC** | Integrated gasification combined cycle |
| **kW** | Kilowatt |
| **kWh** | Kilowatt hour |
| **LCOE** | Levelised Cost of Electricity |
| **Li-ion** | Lithium-ion |
| **LR** | Learning Rate |
| **MW** | Megawatt |
| **MWh** | Megawatt hour |
| **O&M** | Operations and Maintenance |
| **OECD** | Organisation for Economic Cooperation and Development |
| **PHES** | Pumped hydro energy storage |
| **PV** | Photovoltaic |
| **SMR** | Small modular reactor |
| **VCR** | Value of Customer Reliability |
| **VRE** | Variable Renewable Energy |
| **WACC** | Weighted Average Cost of Capital |

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