Australia's National
Science Agency

# GenCost 2021-22

## Final report

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# Acknowledgments

Parts of this report were shared with stakeholders during the period August to September 2021 as shorter documents or webinar presentations. Furthermore, a consultation draft of the report was released in December 2021. The consultation draft was provided as one of several documents supporting AEMO's December 2021 consultation on its 2022 Forecasting Assumptions Update. The consultation commenced on 17 December 2021 and closed 11 February 2022 with many stakeholders providing written submissions. The authors are grateful for all feedback received on these draft documents.

# Executive summary

At the 2021 COP26 in Glasgow, world leaders convened to implement action to limit global average temperature rise to below 2 degrees Celsius. The Conference resulted in additional pledges to achieve net zero emissions (NZE) targets by 2050 and established that if all climate pledges announced to date were met in full and on time, it would be enough to hold the rise in global temperatures to 1.8 °C by 2100.

At a domestic level, the commonwealth government, together with all Australian states and territories aspire to or have legislated NZE by 2050 targets.

Globally, renewables (led by wind and solar) are the fastest growing energy source and the role of electricity is expected to increase materially over the next 30 years with electricity technologies presenting some of the lowest cost abatement opportunities.

Common to global scenarios presented here and by other leading international bodies is the implication that in order to limit emissions, the energy system must evolve and become more diverse. Chiefly: renewable energy is increasingly important, fossil fuels will remain in use (although increasingly challenged), and societies will redefine mobility. Also, Australia's efforts are characterised both by the value chains (and associated emissions) of our energy exports and our own consumption of energy.

In 2019-20, transport (26.5%), electricity supply (25.5%), manufacturing (17.1%) and mining (14.1%) sectors were the largest energy consumers. In electricity supply, fossil fired generation was responsible for 77.4% of supply and renewables the remaining 22.6%, out of which solar PV supplied 7.9% while wind contributed 7.7%.

### GenCost update

GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating electricity generation, storage costs and hydrogen production costs with a strong emphasis on stakeholder engagement. This is the fourth update following the inaugural report in 2018.

Technology costs are one piece of the puzzle. They are an important input to electricity sector analysis which is why we are committed to working with stakeholders to improve the quality of each update. This final report for 2021-22 has been made possible by feedback received throughout the year.

The report encompasses updated current capital cost estimates commissioned by AEMO and delivered by Aurecon. Based on these updated current capital costs, the report provides projections of future changes in costs consistent with updated global electricity scenarios which incorporate different levels of achievement of global climate policy ambition. Levelised costs of electricity (LCOEs) are also included and provide a summary of the relative competitiveness of generation technologies.

### Capital cost projections

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 (with a partial contribution from Australian deployment related to local components of cost). Three global scenarios are explored:

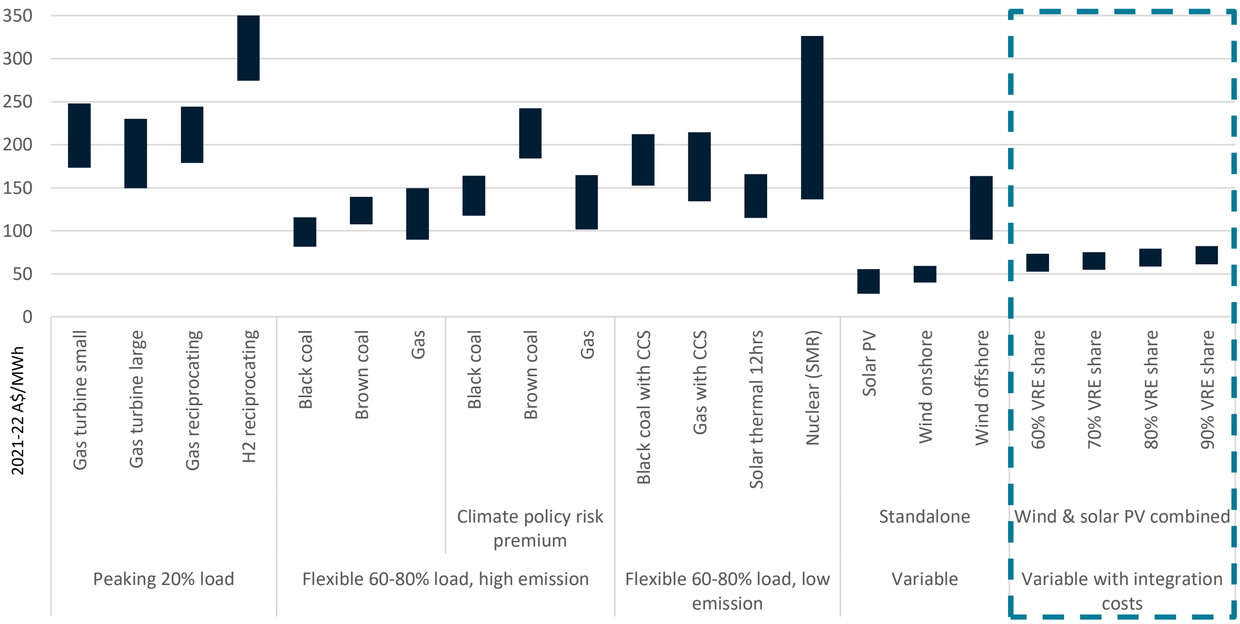
- **Current policies**: Current stated global climate polices, with the most likely assumptions for all other factors such as renewable resource constraints
- **Global NZE by 2050**: A world that is driving towards net zero emissions by 2050 together with high levels of electrification and hydrogen consumption and trade
- **Global NZE post 2050**: A world where most developed countries are striving for net zero emissions by 2050 but others are lagging such that global net zero emissions are reached by 2070.

In the *Global NZE by 2050* scenario, global non-hydro renewable generation reaches a share of 71% by 2050, with the majority sourced from solar photovoltaic (PV) and on- and off-shore wind. Non-hydro renewables also reach a high share of 68% by 2050 in the *Global NZE post 2050* scenario. *Current policies* is projected to see non-hydro renewables reach 34% by 2050.

Carbon capture and storage costs are lowest in the *Global NZE by 2050* as this scenario offers a strong climate policy ambition to justify deploying CCS in electricity generation, hydrogen production and other industry applications. In this scenario, CCS achieves a 12% share of global electricity generation by 2050.

Nuclear generation including small modular reactors achieves global shares of 12% to 15% in 2030 across the scenarios but declines over the remainder of the projection period. Nuclear has a proportionally higher role, at 8% by 2050 in *Current policies* compared to 5% in *Global NZE by 2050* and 7% in *Global NZE post 2050*.

Global supply chains are currently experiencing tight conditions following ongoing restrictions, mixed recovery from the global COVID-19 pandemic and an increase in global energy prices associated with the Ukraine war. This has increased the potential for price pressures. Higher prices have not been observed in this year's update of current costs which are reflective of past conditions. However, the costs for projects that will be procured or completed in the coming year will be subject to these current price pressures. To address this issue in the projections we have assumed a flat profile (after inflation) for all generation technology costs in 2022, with cost reductions, where appropriate, resuming in 2023. Understanding recent changes in capital costs for the different technology options will be a key focus in the development of draft projections for the 2022-23 GenCost publication.




**ES Figure 0-1 Calculated LCOE by technology and category for 2030**

### Levelised cost of electricity

Levelised cost of electricity (LCOE) data is an electricity generation technology comparison metric. It is the total unit costs a generator must recover to meet all its costs including a return on investment. The LCOE is estimated on a common basis for all technologies with one exception. An additional process is undertaken to calculate the integration costs of variable renewables.

The required amount of additional investment depends on the amount or share of variable renewable energy (VRE) generated. We calculated the additional costs of variable renewable generation for annual VRE shares from 60% to 90%[1] for the National Electricity Market (NEM) and Western Australia. We found that the additional costs to support a combination of solar PV and wind generation in 2030 is estimated at between $16 to $28/MWh depending on the VRE share.

These renewable integration costs are similar in level to the findings from the previous GenCost report in 2020-21. However, greater projected cost reductions in onshore wind power have led to an increased preference to combine onshore wind generation and transmission expenditure, with reduced reliance on solar PV and storage to balance energy demand.

All estimates are based on a maximum of costs across nine weather years over which the costs were estimated. When added to variable renewable generation costs and compared to other technology options, these estimates indicate that onshore wind and solar PV remain the lowest cost new-build technologies.

[1] 90% is about as high as variable renewable deployment is likely to need to go as increasing it further would result in the undesirable outcome of shutting down existing non-variable renewable generation from biomass and hydroelectric sources. Approximately 52% will be achieved in 2030 without any new policies.

# 1 Introduction

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 Energy 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 or to manage future electricity costs. 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 sets for these activities or at least have a common reference point for differences.

The report provides an overview of updates to current costs in Section 2. This section draws significantly on updates to current costs provided in Aurecon (2022) and further information can be found in their report. The global scenario narratives and data assumptions for the projection modelling are outlined in Section 3. Capital cost projection results are reported in Section 4 and LCOE results in Section 5. CSIRO's cost projection methodology is discussed in Appendix A. Appendix B provides data tables for those projections which can also be downloaded from CSIRO's Data Access Portal[2].

## 1.1 Scope of the GenCost project and reporting

The GenCost project is a joint initiative of the CSIRO and AEMO to provide an annual process for updating electricity generation and storage cost data for Australia. The project is committed to a high degree of stakeholder engagement as a means of supporting the quality and relevancy of outputs. Each year a consultation draft is released in December for feedback before the final report is completed towards the end of the financial year.

The project is flexible about including new technologies of interest or, in some cases, not updating information about some technologies where there is no reason to expect any change, or if their applicability is limited. GenCost does not seek to describe the set of electricity generation and storage technologies included in detail.

## 1.2 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own in-kind resources. AEMO commissioned Aurecon to provide an update of current electricity generation and storage cost and performance characteristics (Aurecon, 2022). Earlier drafts of Aurecon's report were initially shared with stakeholders during a webinar in September 2021.

[2] Search GenCost at https://data.csiro.au/collections

Project management, workshops, capital cost projections (presented in Section 4) and development of this report are primarily the responsibility of CSIRO.

## 1.3 Incremental improvement and focus areas

There are many assumptions, scope and methodological considerations underlying electricity generation and storage 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.

In this report, we have made two major improvements. The first is global modelling now endogenously determines the hydrogen production technology mix under each scenario as well as the additional electricity demand imposed by hydrogen production from electrolysis, which is in addition to other electricity demand. The second improvement is that we include deployment of carbon capture and storage outside of the electricity sector. This is partly captured through the allowed use of CCS in hydrogen production. However, we also include an assumption regarding CCS deployment outside of electricity and hydrogen.

## 1.4 The GenCost mailing list

The GenCost project would not be possible without the input of stakeholders. No single person or organisation is able to follow the evolution of all technologies in detail. We rely on the collective deep expertise of the energy community to review our work before publication to improve its quality. To that end the project maintains a mailing list to share draft outputs with interested parties. The mailing list is open to all. To join, use the contact details on the back of this report to request your inclusion. Some draft GenCost outputs are also circulated via AEMO's Forecasting Reference Group mailing list which is also open to join via their website.

## 1.5 Technology selection principles

As we enter our fourth year of the GenCost project we have decided to review our processes for inclusion of technologies. Our general goal is to keep the technology list to a manageable level but include new technologies as their relevance increases or the available information becomes more mature and transparent. A set of technology selection principles has been included in Appendix C. Feedback on these draft principles as part of this consultation is welcome.

## 1.6 Overview of consultation draft feedback and changes

There was a broad range of feedback provided on the December 2021 consultation draft. CSIRO also continues to review its own work, particularly as new information becomes available. We summarise stakeholder feedback, how they have been addressed and other additional CSIRO-led changes under the following themes.

### 1.6.1 Technology learning rates

Technology learning rates are an important input into the cost projections. They are based on historical data or on learning rates achieved by technologies at a similar stage of development. They determine the cost reduction for each doubling of cumulative capacity deployed. We implement multi-stage learning rates in some cases because learning rates have a tendency to decline as technologies mature. We have continued to review offshore wind learning rates. Additional data sources indicate the range of plausible future learning rates could be wider than previously expected and these have been incorporated in the final projections.

### 1.6.2 Renewable resource constraints

Each region of the world has a finite resource of renewable energy. Factors like competing land uses reduce the potential resource further. However, technology can increase the amount of resource that can be accessed. For example, floating solar means that solar can be installed on bodies of water. We do not specifically include these non-standard installation approaches because we are unable to include a large number of technologies. Instead, we relax the assumptions used in the Current policies scenario so that more renewable resources are available in Global NZE post 2050 and Global NZE by 2050 scenarios. In the final report we have changed the approach for rooftop solar so that the same resources are available in all three scenarios. Given the avoided transmission and distribution costs, a complete relaxation of resource constraints on rooftops was leading to unrealistically high uptake of this technology in the consultation draft. This has resulted in a reduction in rooftop PV uptake under the Global NZE by 2050 and Global NZE post 2050 scenarios respectively. The main technologies to benefit from this reduction are gas with carbon capture and storage and also large-scale PV and storage (recognising that small-scale PV was often deployed with small-scale storage in previous modelling).

### 1.6.3 Hydrogen electrolyser costs

Feedback suggested that the long-term cost range for hydrogen electrolysers did not adequately represent the uncertainty in future cost outcomes. In particular there should be a higher cost scenario. The consultation draft projections did converge significantly by 2050. The learning rates are one driver of this outcome. The increase in scale of electrolysers deployed is also partly responsible for cost reductions. To create a higher cost outcome for the Current policies scenario, we have assumed that electrolysers are not as large in that scenario owing to less demand for hydrogen which is consistent with lower global climate policy ambition (scenario assumptions are discussed further in Section 3 of this report).

### 1.6.4 Biomass costs

Stakeholder proposed changes to biomass technology data in GenCost were:

- Include feedstocks other than wood chips
- Lower capital costs on the basis of overseas project costs
- Adjust $/kW costs for differences in capacity factors

- Include other mature technologies such as biogas digesters combined heat and power plant
- Increase capacity factors and energy efficiency to that of an ultra-supercritical plant

CSIRO is not considering adjusting $/kW costs for differences in capacity factors. The levelised cost of electricity data already provided is the appropriate metric for comparing technologies on a common basis. Capital costs only represent one part of total generation costs.

Aurecon adjusts overseas costs for exchanges rates, differences in the cost of labour and in regulations and transport costs. Aurecon also notes that projects that have been delivered in Australia have frequently experienced considerable delays and cost overruns.

Woodchips were chosen on the basis of their availability and scale. Other feedstocks could be considered in the future if they are deemed a priority. Note that the range of fuel costs in the levelised cost of electricity analysis is from $0.5 to $2/GJ. One potential interpretation of this cost range could be different feedstocks. The Aurecon (2022) report provides costs for biogas from biomass digesters and biodiesel. Information on these additional bioenergy technologies was not included in GenCost because it is not focussed on fuel costs. Our biomass technology is a subcritical and electricity-only, not a combined power and heat ultra-supercritical plant, so it is not appropriate to increase the efficiency. However, we have increased the capacity factor range used in the levelised cost of electricity analysis from 60% to 80% consistent with other baseload plant.

We will continue to apply the principle of trading off completeness against the cost to the project of updating a larger technology list.

### 1.6.5 On- and off-shore wind

Feedback indicated that consultation draft costs for onshore wind were below those being observed by stakeholders. Also, Aurecon's offshore wind costs were for a project delivered several years in the future. Aurecon conducted a further review of onshore wind data which resulted in current costs being revised upwards. CSIRO also made an adjustment to its interpretation of Aurecon's offshore wind costs so that they meet our definition of current costs (that is, projects completed in the current year).

### 1.6.6 Short term cost pressures

It has been widely reported in the media that Australia and the world are currently undergoing an inflationary cycle affecting many raw materials relevant to generation and storage technologies. To reflect this state of affairs the consultation draft assumed that the real cost of technologies would be flat in the first projection year, which for some technologies represents a significant departure from an otherwise long track record of year-on-year real cost reductions. In current price terms, the assumption means that generation and storage technology costs will rise with the general level of inflation.

Since the consultation draft was released, we have had the opportunity to review quarterly inflation data and can confirm that the data supports the media reports. Despite this extra data, we have concluded that we are unable to improve upon the approach we took in the consultation draft. We do not have a sufficient time series of data to assign a more specific level of change in real costs or to predict the duration of the inflationary cycle. We do know central banks have begun to tighten monetary policy with the aim of moderating inflation in Australia and elsewhere.

### 1.6.7 Global and domestic fossil fuel prices

For many years it has been the practice of the International Energy Agency (IEA) to assume that global fossil fuel prices will be lower in scenarios that have stronger climate policy ambition. The rationale is that as demand for fossil fuels fall then prices will follow. However, it is our view that it is better to have a common set of fossil fuel prices across all scenarios. In the long run, fossil fuel prices will fluctuate due to cycles of demand and supply imbalances (e.g., the world is experiencing a supply shortage in 2022). However, underlying these fluctuations, prices should track the cost of production in the long run given the competitive nature of commodity markets. This relationship holds whether demand is falling or rising over the long run.

Domestic fossil fuel prices used in the levelised cost of electricity analysis have been updated to be more consistent with AEMO's ISP data assumptions. The largest increase compared to the 2020-21 report was in gas prices.

### 1.6.8 Common basis for application of Aurecon costs

The capital cost data reported in GenCost does not always align with those reported in AEMO's Input and Assumptions workbooks nor with Aurecon's original data for the current year. Stakeholders have requested closer alignment, or if not possible, more background information on the differences. The differences have reflected a number of factors, some of which can be avoided and others which cannot. While land costs are included in Aurecon data, it is not reported in their total capital costs whereas CSIRO and AEMO do include this cost component. CSIRO and AEMO take a common approach on this point and have improved their alignment on the timing and overlap between calendar and financial years reported. AEMO makes further adjustments which are necessary to properly apply the data to their forecasting and planning work and will provide more detail on these adjustments in their documentation.

### 1.6.9 Nuclear costs

We have had a range of feedback into the assumed current costs for nuclear SMR over several years reflecting the difficulty of finding good evidence for costs in circumstances where a technology is not currently being deployed. This year only one submission was received but it continues the theme established in previous years that current costs of nuclear SMR should be lower. Vendors seeking to encourage the uptake of a new technology have proposed theoretical cost estimates, but these cannot be verified until proven through a deployed project.

Our current cost estimate is from GHD (2018) and EFWG (2019). The basis of the GHD (2018) estimate was the International Energy Agency and Nuclear Energy Association report, *Projected costs of electricity generation 2015*. That report proposed that, while there is potential for significant cost reductions in the future, at its current stage of development, nuclear SMR typically costs 50% to 100% more than large scale nuclear. If we use the 100% value of large scale nuclear for Australia (reflecting our limited experience in nuclear generation) and a 0.7 US$/A$ exchange rate the outcome matches the GHD (2018) estimate of $16,000/kW. It is also consistent with the higher end of more recent “first of a kind” estimates from EFWG (2019) which stakeholder feedback proposed should be used as the preferred data source.

Consistent with the approach we established in GenCost 2020-21, we do not report any costs for the 2020s. Costs are reported from 2030 reflecting the fact that no Australian SMR project is likely to be deployed before this date. Two of GenCost’s projections of the after-learning future cost of nuclear SMR in the 2030s are consistent with “nth of a kind” estimates such as EFWG (2019). One estimate is much higher, representing a world where SMR receives insufficient funding to achieve the amount of deployment needed to reduce costs. We believe this is plausible given competition for project funding, the potential for nuclear safety issues to emerge[3] and the availability of mature low-cost alternatives that can be deployed at a faster rate.

### 1.6.10 Levelised cost of electricity

Stakeholders have requested that we add a hydrogen peaking generator to the technologies that are included in the levelised cost of electricity (LCOE) analysis. Hydrogen is currently a more expensive fuel than natural gas. However, hydrogen could be used in the electricity system if it is necessary to produce electricity without any greenhouse gas emissions or if hydrogen costs can be made low enough to compete with gas. Hydrogen costs have been sourced from AEMO’s ISP data assumptions.

We have also made two further changes to the LCOE data we present. Offshore wind has been included recognising that this technology is coming closer to being deployed in Australia. We have also removed small scale biomass generation from the figures which compare the LCOE of generation technologies. This is because we regard small scale biomass as being a behind-the-meter technology[4] which is primarily competing with retail electricity. It could therefore be misleading to present it alongside the costs of wholesale generation market technologies. However, we continue to include the LCOE of small-scale biomass in the relevant appendix table.

[3] The Fukushima nuclear disaster represents an historical event of this type. A current event is the additional security complications associated with nuclear power in the Ukraine war.

[4] It’s size also means that it may be in the unscheduled NEM market category.

# 2 Current technology costs

## 2.1 Current cost definition

Our definition of current costs are the costs that have been demonstrated to have been incurred for projects completed in the current financial year (or within a reasonable period before). We do not include in our definition of current costs, costs that represent quotes for delivery of projects in future financial years or project announcements.

While all data is useful in its own context, our approach reflects the objective that the data must be suitable for input into electricity models. The way most electricity models work is that investment costs are incurred either before (depending on construction time assumptions) or in the same year as a project is available to be counted as a new addition to installed capacity[5]. Hence, current costs and costs in any given year must reflect the costs of projects completed in that year. Quotes received now for projects to be completed in future years are only relevant for future years. This point is particularly relevant for technologies with fast reducing costs (e.g., batteries). In these cases, lower cost quotes will become known well in advance of those costs being reflected in recently completed deployments.

For technologies that are not frequently being constructed, our approach is to look overseas at the most recent projects constructed. This introduces several issues in terms of different construction standards and engineering labour costs which have been addressed by Aurecon (2022). Aurecon (2022) also provide more detail on specific definitions of the scope of cost categories included. Aurecon cost estimates are provided for Australia in Australian dollars. CSIRO makes adjustments to the data when used in global modelling to take account of regional differences in costs.

## 2.2 Cost source

We have used data supplied by Aurecon (2022) which is consistent with either the middle of financial year 2021-22 or end of 2021. Aurecon provides several measures of project capacity. We use the not-summer rating to determine $/kW costs.

## 2.3 Updates to current costs

AEMO commissioned Aurecon (2022) to provide an update of current cost and performance data for existing and selected new electricity generation, storage and hydrogen 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.

[5] This is not strictly true of all models but is most true of long-term investment models. In other models, investment costs are converted to an annuity (adjusted for different economic lifetimes), or additional capital costs may be added later in a project timeline for replacement of key components.

Aurecon has provided costs for small scale batteries for the first time. CSIRO has updated costs for technologies which are more rarely deployed such as tidal/current and wave energy.

Pumped hydro has also not been updated by Aurecon (2022), but we have revised this data to be consistent with AEMO's July 2021 ISP Input and Assumptions Workbook. Nuclear SMR current costs are not reported since there is no prospect of a plant being deployed before 2030. However, some improved data on nuclear SMR may be available in future reports[6] and projected capital costs for SMR have been included from 2030 onward.

## 2.4 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2021-22) cost estimates (drawing primarily on the Aurecon (2022) update) for electricity generation technologies with the four most recent previous reports: GenCost 2019-20, GenCost 2018, Hayward and Graham (2017) (also CSIRO) and CO2CRC (2015) which we refer to as APGT (short for Australian Power Generation Technology report). All costs are expressed in real 2021-22 Australian dollars and represent overnight costs.

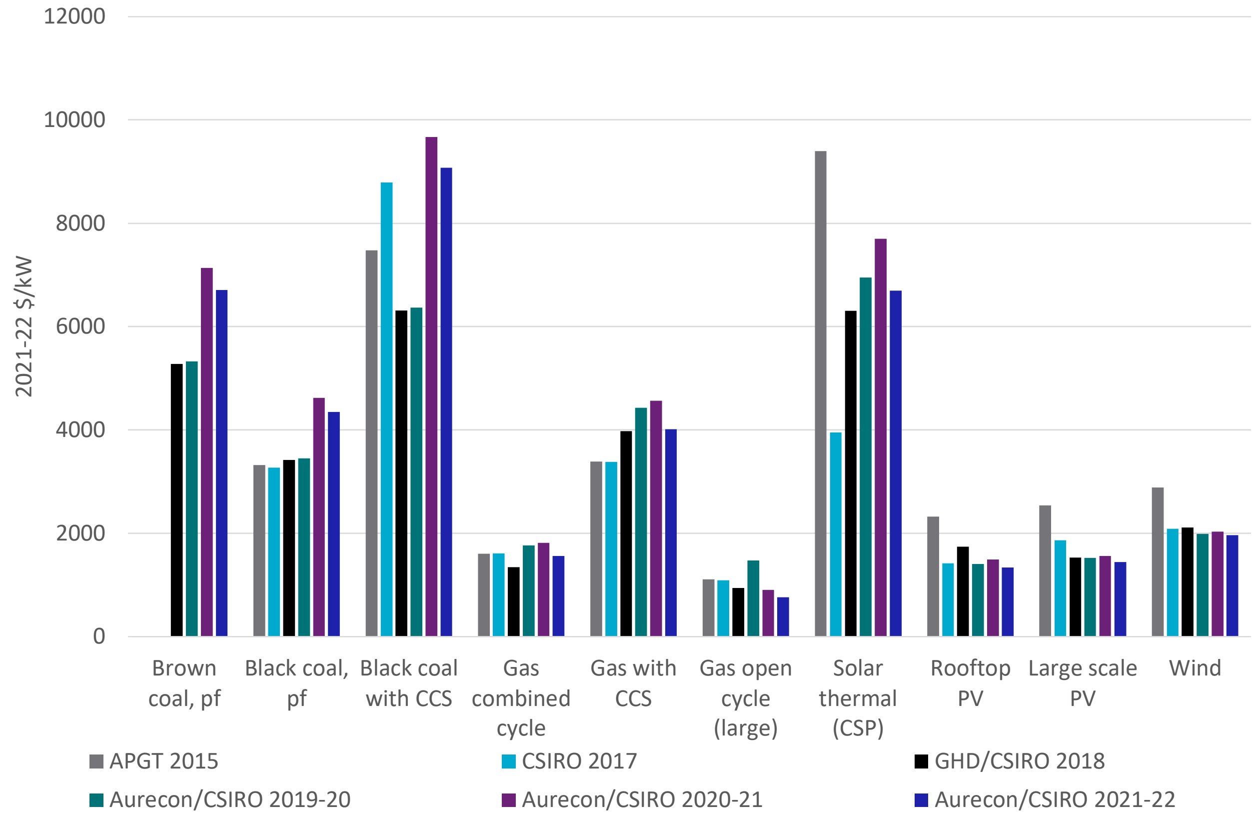



**Figure 2-1 Comparison of current cost estimates with previous work**

[6] The Australian Nuclear Science and Technology Organisation has joined an International Atomic Energy Agency project to appraise the costs of nuclear SMR. The project is due for completion in December 2024. Economic Appraisal of Small Modular Reactors Projects: Methodologies and Applications | IAEA. EFWG (2019) is the most recently available data source.

CSIRO's estimate for rooftop solar PV cost is included in the Aurecon (2021, 2022) and GHD (2018) data as that technology is not part of those sources. Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme. All data has been adjusted for inflation.

These current costs represent projects that would have reached financial close before the current inflationary pressure had begun to be felt. Coal generation capital costs are slightly lower. The lack of Australian construction data means there will always be a range of interpretations when converting overseas data to the Australian context. Solar thermal costs have also decreased and now include 12 hours storage (previous data was for 8 hours storage). Gas, wind and solar PV cost estimates have been relatively stable reflecting better data availability for Australian projects. Their updated costs are all slightly lower.

## 2.5 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[7] of battery and pumped hydro energy storage (PHES) in \$/kW and \$/kWh. Total cost basis means that the costs are calculated by taking the total project costs divided by the capacity in kW or kWh[8]. As the storage duration of a project increases then more batteries or larger reservoirs need to be included in the project, but the power components of the storage technology remain constant. As a result, \$/kWh costs tend to fall with increasing storage duration (Figure 2-2). The downward trend flattens somewhat with batteries since its power component, mostly inverters, is relatively small but adding more batteries is costly. However, the hydro turbine in a PHES project is a large capital expense while adding more reservoir is less costly. As a result, PHES costs fall steeply with more storage duration.

Conversely, the costs in \$/kW increase as storage duration increases because additional storage duration adds costs without adding any power rating to the project (Figure 2-3). Additional storage duration is most costly for batteries. These trends are one of the reasons why batteries tend to be more competitive in low storage duration applications, while PHES is more competitive in high duration applications. A combination of battery and pumped hydro with different durations may be required depending on the behaviour of other generation in the system, particularly the scale of variable renewable generation (see Section 5).

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[7] The storage duration used throughout this report refers to the maximum duration for which the storage technology can discharge at maximum rated power. However, it is important to note that every storage technology can discharge for longer by doing so at a rate lower than their maximum rated power

[8] Component costs basis is when the power and storage components are separately costed and must be added together to calculate the total project cost.

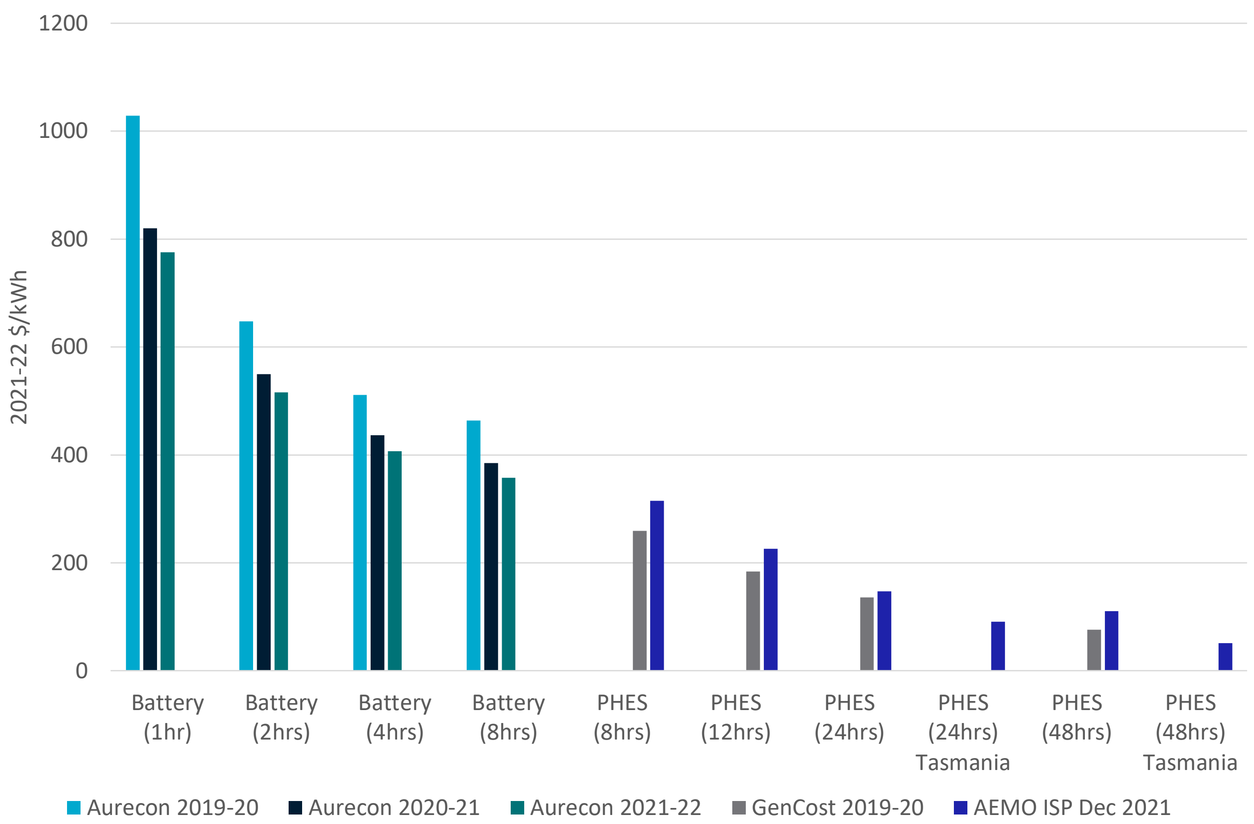


**Figure 2-2 Capital costs of storage technologies in $/kWh (total cost basis)**

Round trip efficiency, project design life and the potential for co-location also play a role in competitiveness of alternative storage technologies. Depth of discharge in batteries is also a relevant factor. However, all Aurecon battery costs are on a usable capacity basis such that depth of discharge is 100%. Aurecon (2022) also includes estimates of battery costs when they are integrated within an existing power plant and can share some of the power conversion technology. This results in a 9% lower battery cost for a 1-hour duration battery, scaling down to a 3% cost reduction for 8 hours duration. PHES is more difficult to co-locate.

Battery current costs have experienced a modest 5% to 6% decline on previous year's current costs. These are based on projects deployed. PHES current cost estimates have not significantly changed but have a wider range of uncertainty owing to the greater influence of site-specific issues. Batteries are more modular and as such costs are relatively independent of the site. As an indicator of the influence of site costs, we have included the cost of Tasmania pumped hydro for 24 and 48 hours duration.

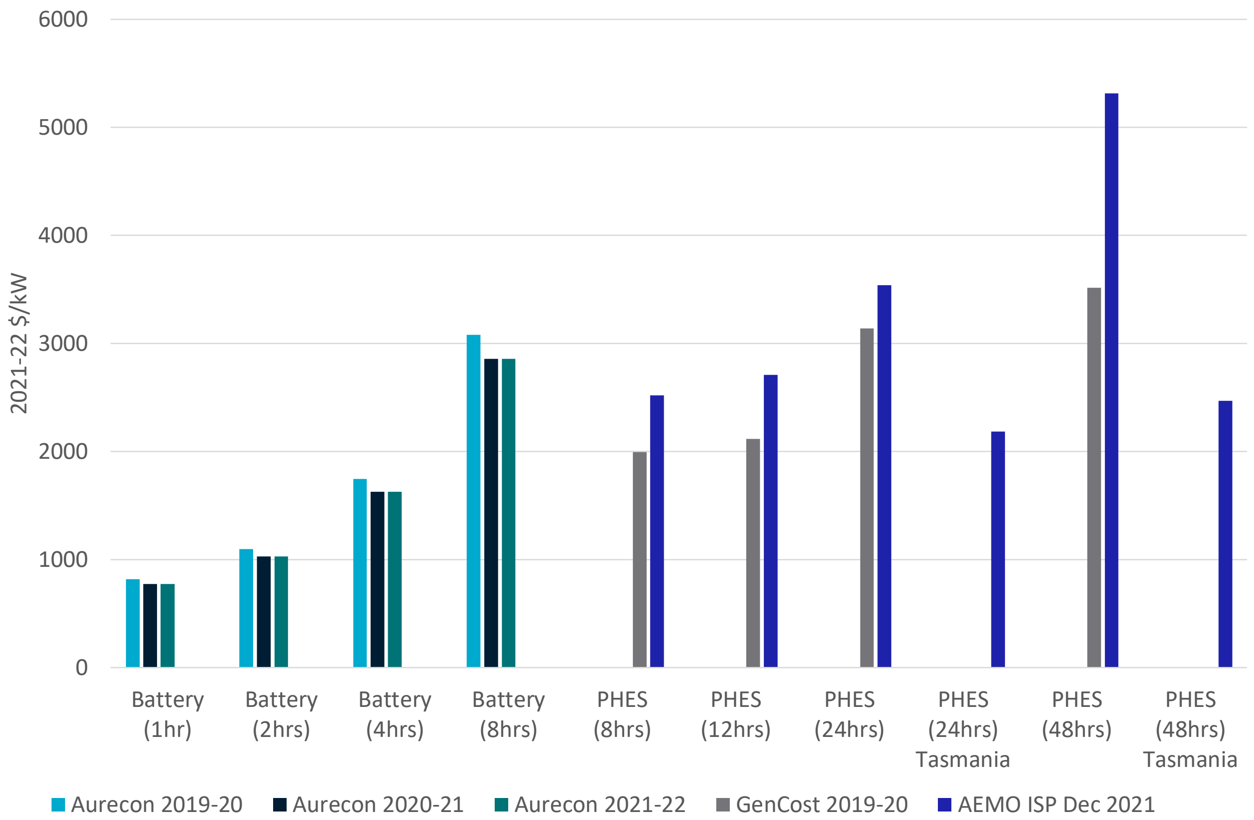


**Figure 2-3 Capital costs of storage technologies in $/kW (total cost basis)**

# 3 Scenario narratives and data assumptions

The scenarios have been revised and renamed compared to previous GenCost reports. We would prefer to minimise scenario changes so the projections can be compared with previous GenCost reports. However, significant changes were required for 2021-22 due to several developments since the 2020-21 project cycle was complete.

**Greater focus on net zero emission scenarios**: The International Energy Agency's release of their *Net Zero by 2050* report has set a strong benchmark for the possible strongest global action for achieving the goal of limiting global warming to 1.5°C. We had previously aligned our High VRE scenario to this IEA scenario. The report has provided more detail for how this scenario is implemented which we have adopted. We have also adopted the scenario name *Global NZE by 2050* which provides a clearer description.

**Greater confidence in role of wind and solar PV**: GenCost previously included a Diverse technology scenario which explored the case where deployment of variable renewables was more limited and other technologies played a larger role. Stakeholder feedback received during AEMO's 2020-21 Australian scenario development process found that it was unlikely that alternative technologies will be able to compete in a significant way with renewables. This reflects relatively uncompetitive gas prices, a lack of confidence in the future cost competitiveness of CCS technologies and abundant low-cost renewable resources. Some of these concerns about a Diverse technology scenario are specific to Australia's circumstances. However, there are countries with similar energy resource profiles where the Diverse technology scenario also lacks plausibility. This scenario has been removed.

**Central scenario has become highest cost:** The previous Central scenario included current policies and therefore represents no change in global climate policy action. With the removal of the Diverse technology scenario the Central scenario becomes the highest technology cost scenario. We retain this scenario but rename it *Current policies*. It is appropriate to create a new middle-ground scenario that sits between *Current policies* and Net zero by 2050. We have named this new scenario *Global NZE post 2050*.

These changes were shared with the GenCost mailing list for feedback during August to September an on the Consultation report. Table 3-1 summarises the scenario name changes.

Table 3-1 Previous and new GenCost scenario names

| Previous GenCost | Central | Diverse technology | High VRE |
|---|---|---|---|
| **GenCost 2021-22** | Current policies | Global NZE post 2050 | Global NZE by 2050 |

While we no longer have confidence in the narrative of the previous Diverse technology scenario, it was useful for broadening out the range of technology cost projections. To ensure that the new scenarios also produce a broad range of projections, we have modified our approach to technology learning curves by including greater difference in assumed learning rates between scenarios. Previously, learning rates were constant across scenarios apart from a few exceptions (e.g., batteries). The new learning rate assumptions are discussed further below.

## 3.1 Scenario narratives

The global climate policy ambitions for the *Current policies*, *Global NZE post 2050* and *Global NZE by 2050* scenarios have been adopted from the International Energy Agency's 2021 World Energy Outlooks (IEA, 2021) scenario matching to the Stated Policies scenario, Sustainable Development Scenario respectively and Net Zero Emissions by 2050. IEA (2021) has slightly de-emphasised the Sustainable Development Scenario, however we find it useful as a middle-ground scenario. Various elements, such as the degree of vehicle electrification and hydrogen production, are also consistent with the IEA scenarios.

### 3.1.1 Current policies

The *Current policies* scenario applies a 2.6 degrees of global warming consistent climate policy (using a combination of carbon prices and other climate policies[9]). This represents mid- 2021 climate and renewable energy policy commitments with no extension beyond targets existing at that time[10]. This implies that the 2030 Paris Nationally Determined Commitments are met but that the planned ramping up of ambition to prevent a greater than 2 degrees increase in temperature is limited to only those countries that had committed to further action. This scenario has the strongest constraints applied with respect to global variable renewable energy resources and the slowest technology learning rates. Subsequently, electricity sector greenhouse gas abatement costs are higher. This is consistent with a lack of any further progress on emissions abatement beyond Paris commitments. Technical approaches for managing balancing of variable renewable electricity are based on current technology. Demand growth is moderate with moderate electrification of transport and limited hydrogen production and utilisation.

### 3.1.2 Global NZE post 2050

The *Global NZE post 2050* has moderate renewable energy constraints and middle of the range learning rates. It has a carbon price and other policies consistent with a 1.65 degrees of warming climate change ambition which provides the investment signal necessary to deploy these technologies. Developed countries are largely aiming for net zero emissions by 2050 but other countries are lagging such that worldwide net zero emissions are not achieved until 2070. Hydrogen trade (based on a combination of gas with CCS and electrolysis) and transport and industry electrification are significantly higher than in *Current policies*.

[9] The application of a combination of carbon prices and other non-carbon price policies is consistent with the approach applied by the IEA. While we directly apply the IEAs published carbon prices, we design our own implementation of non-carbon price policies to ensure we match the emissions outcomes in the relevant IEA scenario. Structural differences between GALLM and the IEA's models means that we cannot implement the exact same non-carbon price policies. Even if our models were the same, the IEA's description of non-carbon price policies is insufficiently detailed to apply directly.

[10] To be consistent with the IEA World Energy Outlook, this only includes policies announced up until that report's publication date. This also does not include updated country targets associated with 26th Conference of Parties due to timing constraints

### 3.1.3 Global NZE by 2050

Under the *Global NZE by 2050* scenario there is strong climate policy consistent with maintaining temperature increases of 1.5 degrees of warming and achieving net zero emissions by 2050 worldwide. The achievement of these abatement outcomes is supported by the strongest technology learning rates and the least constrained (physically and socially) access to variable renewable energy resources. Balancing variable renewable electricity is less technically challenging. Reflecting the low emission intensity of the predominantly renewable electricity supply, there is an emphasis on high electrification across sectors such as transport, hydrogen-based industries and buildings leading to the highest electricity demand across the scenarios.

**Table 3-2 Summary of scenarios and their key assumptions**

| Key drivers | Global NZE by 2050 | Global NZE post 2050 | Current policies |
|---|---|---|---|
| **IEA WEO scenario alignment** | Net zero emission by 2050 | Sustainable development scenario | Stated policies scenario |
| **$CO_2$ pricing / climate policy** | Consistent with 1.5 degrees world | Consistent with 1.7 degrees world (or 1.5 if negative abatement technologies deployed by 2070) | Consistent with 2.6 degrees world |
| **Renewable energy targets and forced builds / accelerated retirement** | High reflecting confidence in renewable energy | Renewable energy policies extended as needed | Current renewable energy policies |
| **Demand / Electrification** | High | Medium-high | Medium |
| **Learning rates[1]** | Stronger | Normal maturity path | Weaker |
| **Renewable resource & other renewable constraints[2]** | Less constrained | Existing constraint assumptions | More constrained than existing assumptions |
| **Constraints around stability and reliability of variable renewables** | New low-cost solutions | Conventional solutions | Conventional solutions but less demand for them |
| **Decentralisation** | Less constrained rooftop solar photovoltaics (PV)[2] | Existing rooftop solar PV constraints[2] | More constrained rooftop solar PV constraints[2] |

1 The learning rate is the potential change in costs for each doubling of cumulative deployment, not the rate of change in costs over time. See Appendix A for assumed learning rates.
2 Existing large-scale and rooftop solar PV renewable generation constraints are as shown in Table 3-8.

### 3.1.4 Technologies and learning rates

As we explain further in Appendix A, we use two global and local learning models (GALLM). One is of the electricity sector (GALLME) and the other of the transport sector (GALLMT). GALLME projects the future cost and installed capacity of 31 different electricity generation and energy storage technologies and now two hydrogen production technologies. Where appropriate, these have been split into their components of which there are 48. 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 Table 3-3, Table 3-4 and Table 3-5 showing the relationship between generation technologies and their components and the assumed learning rates under the central scenario (learning is on a global (G) basis, local (L) to the region, or no learning (-) is associated).

The potential for local learning means that technology costs are different in different regions in the same time period. This has been of particular note for technology costs in China which can be substantially lower than other regions. GALLME uses current costs from Aurecon (2022) to calibrate 2020 Australian costs in GALLME. For technologies not commonly deployed in Australia, these costs can be higher than other regions. However, the inclusion of local learning assumptions in GALLME means that they can quickly catch up to other regions if deployment occurs. However, they will not always fall to levels seen in China due to differences in production standards for some technologies. That is, to meet Australian standards, the technology product from China would increase in costs and align more with other regions. Regional labour construction and engineering costs also remain a source of differentiation.

To provide a range of capital cost projections for all technologies, we have varied learning rates for technologies where there is more uncertainty in their learning rate. We focus on variable renewable energy given that these technologies tend to be lower cost and crowd out opportunities for competing low emission technologies. Table 3-3 shows the learning rates by scenario for solar PV, electrolysis and ocean energy (wave and tidal). The learning rates for batteries, which support the integration of variable renewable technologies, are shown in Table 3-4. The remainder of learning rate assumptions, which do not vary by scenario are shown in Table 3-5. Up to two learning rates are assigned with LR1 representing the initial learning rate during the early phases of deployment and LR2, a lower learning rate, that occurs during the more mature phase of technology deployment.

**Table 3-3 Assumed technology learning rates that vary by scenario**

| Technology | Scenario | Component | LR 1 (%) | LR 2 (%) | References |
|---|---|---|---|---|---|
| **Photovoltaics** | Current policies | G | 35 | 10 | (IEA 2021, IRENA, 2021, Fraunhofer ISE, 2015) |
| | | L | - | 5 | |
| **Photovoltaics** | Global NZE by 2050 | G | 35 | 10 | |
| | | L | - | 15.5 | |
| **Photovoltaics** | Global NZE post 2050 | G | 35 | 10 | |
| | | L | - | 10 | |
| **Electrolysis** | Current policies | G | 10 | 5 | |
| | | L | 10 | 5 | |
| **Electrolysis** | Global NZE by 2050 | G | 18 | 9 | (Schmidt et al., 2017) |
| | | L | 18 | 9 | |

| | | | | | |
|---|---|---|---|---|---|
| **Electrolysis** | Global NZE post 2050 | G | 10 | 5 | |
| | | L | 10 | 5 | |
| **Ocean** | Current policies | G | 10 | 5 | |
| | Global NZE by 2050 | G | 20 | 10 | |
| | Global NZE post 2050 | G | 14 | 7 | (IEA, 2021) |
| **Offshore wind** | Current policies | G | 10 | 5 | (Samadi, 2018; Zwaan, et al. 2021;Voormolen et al. 2016; IEA, 2021) |
| | Global NZE by 2050 | G | 20 | 10 | |
| | Global NZE post 2050 | G | 15 | 7 | |

**Solar photovoltaics is listed as one technology with global and local components 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 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.**

**Table 3-4 Assumed utility scale energy storage learning rates by scenario**

| Technology | Scenario | Component | LR 1 (%) | LR 2(%) |
|---|---|---|---|---|
| **Utility scale energy storage – Li-ion** | Current policies | G | - | 7.5 |
| | | L | - | 7.5 |
| **Utility scale energy storage – flow batteries** | Current policies | G | - | 15 |
| **Utility scale energy storage – Li-ion** | Global NZE post 2050 | G | - | 10 |
| | | L | - | 10 |
| **Utility scale energy storage – flow batteries** | Global NZE post 2050 | G | - | 15 |
| | | L | - | 10 |
| **Utility scale energy storage – Li-ion** | Global NZE by 2050 | G | - | 15 |
| | | L | - | 15 |
| **Utility scale energy storage – flow batteries** | Global NZE by 2050 | G | - | 15 |
| | | L | | 15 |

**Li-ion batteries are a component that is used in both PV with storage and utility scale Li-ion battery energy storage. Installation BOP is a component of utility scale battery storage that is shared between both types of utility scale battery storage. Source of High VRE learning rate and flow battery learning rate (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015). Central and Diverse Technology Li-ion learning rates based on CSIRO estimates.**

Table 3-5 Assumed technology learning rates that are the same under all scenarios

| Technology | Component | LR 1 (%) | LR 2 (%) | References |
|---|---|---|---|---|
| **Coal, pf** | - | - | - | |
| **Coal, IGCC** | G | - | 2 | (IEA, 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; McDonald and Schrattenholzer, 2001) |
| **Gas peaking plant** | - | - | - | |
| **Gas combined cycle** | - | - | - | |
| **Nuclear** | G | - | 3 | (IEA, 2008) |
| **SMR** | G | 20 | 10 | (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001) |
| **Diesel/oil-based generation** | - | - | - | |
| **Reciprocating engines** | - | - | - | |
| **Hydro** | - | - | - | |
| **Biomass** | G | - | 5 | (IEA, 2008; Neij, 2008) |
| **Concentrating solar thermal (CST)** | G | 14.6 | 7 | (Hayward & Graham, 2013) |
| **Onshore wind** | G | - | 4.3 | (IEA, 2021; Hayward & Graham, 2013) |
| | L | - | 11.3 | As above |
| **CHP** | - | - | - | |
| **Conventional geothermal** | G | - | 8 | (Hayward & Graham, 2013) |
| | L | 20 | 20 | (Grübler et al., 1999; Hayward & Graham, 2013; ; McDonald and Schrattenholzer, 2001) |
| **Fuel cells** | G | - | 20 | (Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010) |
| **Pumped hydro** | G | - | | |
| | L | - | 20 | (Grübler et al., 1999; McDonald and Schrattenholzer, 2001) |
| **Steam methane reforming with CCS** | G | 10 | 5 | (EPRI, 2010; Rubin et al., 2007) |
| | L | 20 | 10 | As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001) |

Pf=pulverised fuel, IGCC=integrated gasification combined cycle, CHP=combined heat and power, SMR=small modular reactor

Geothermal BOP includes the power generation.

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.

In addition to the offshore wind learning rate, we have included an exogenous increase in the capacity factor up to the year 2050 of 6% in lower resource regions, and 7% in higher resource regions, up to a maximum of 55%, in capacity factor.

### 3.1.5 Electricity demand and electrification

Various elements of underlying electricity demand are sourced from the World Energy Outlook (IEA, 2020; IEA 2021). Demand data is provided for the Sustainable Development Scenario (SDS), which is used in our *Global NZE post 2050* scenario. The demand data from the Stated Policies (STEPS) scenario is used in our Current policies scenario. *Global NZE by 2050* demand is sourced from the Net zero emissions by 2050 scenario. We also allow for some divergence from IEA demand data in all scenarios to accommodate differences in our modelling approaches and internal selection of the contribution of electrolysis to hydrogen production.

#### Global vehicle electrification

Global adoption of electric vehicles (EVs) by scenario is projected using an adoption curve calibrated to a different shape to correspond to the matching IEA World Energy Outlook scenario sales shares to ensure consistency in electricity demand. The rate of adoption is highest in the *Global NZE by 2050* scenario, medium in the *Global NZE post 2050* scenario and low in the *Current policies* scenario consistent with climate policy ambitions. The shape of the adoption curve varies by vehicle type and by region, where countries that have significant EV uptake already, such as China, Western Europe, India, Japan, North America and rest of OECD Pacific, are leaders and the remaining regions are followers. Cars and light commercial vehicles (LCV) have faster rates of adoption, followed by medium commercial vehicles (MCV) and buses. The EV adoption curves for the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios are shown in Figure 3-1, Figure 3-2 and Figure 3-3 respectively. The adoption rate is applied to new vehicle sales shares.

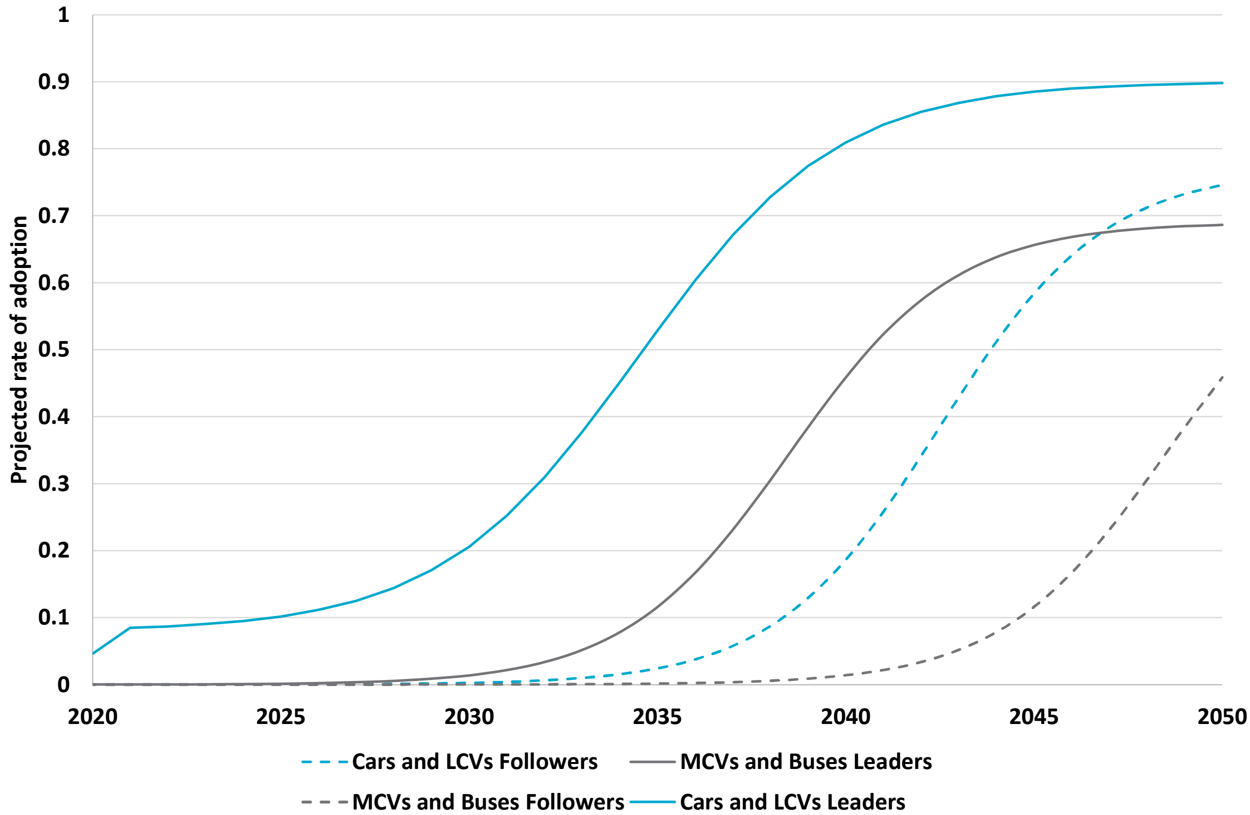


**Figure 3-1 Projected EV sales share under the *Current policies* scenario**

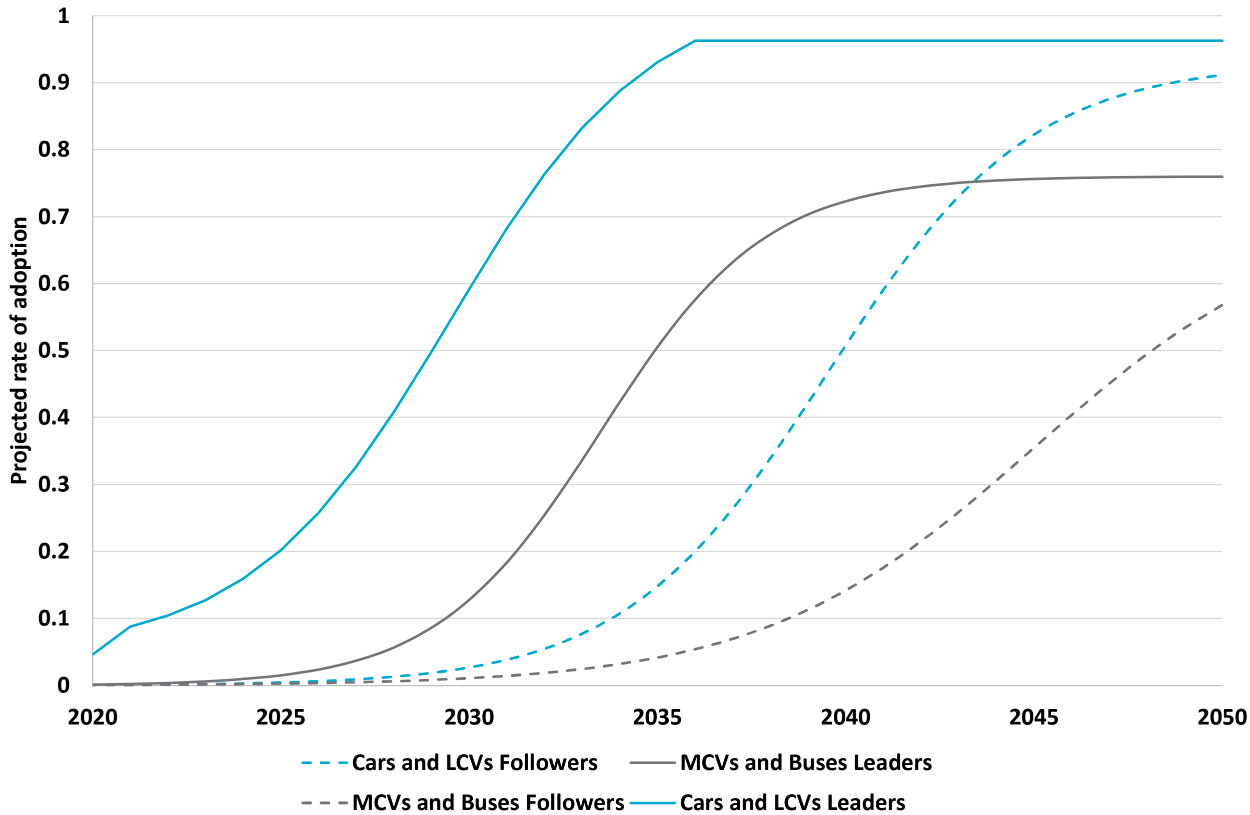


**Figure 3-2 Projected EV adoption curve (vehicle sales share) under the *Global NZE by 2050* scenario**

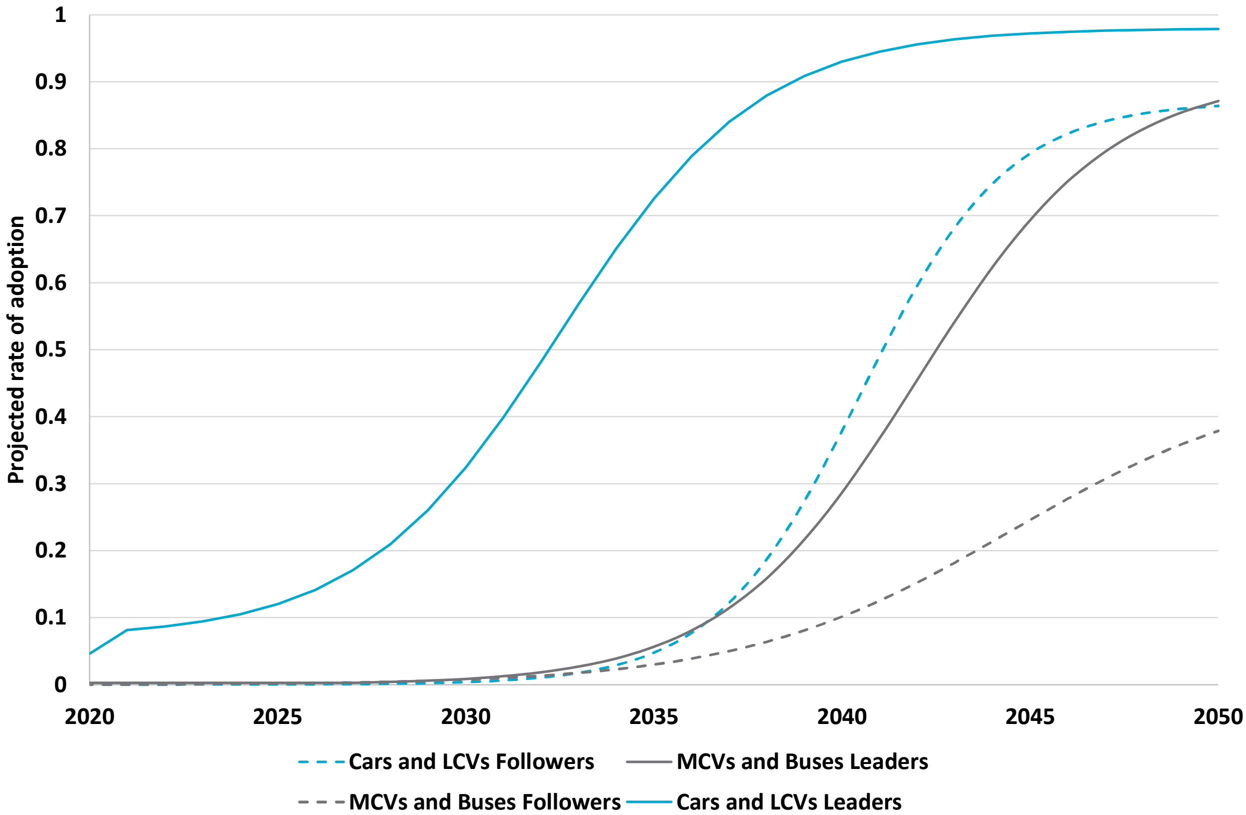


Figure 3-3 Projected EV sales share under the *Global NZE post 2050* scenario

### 3.1.6 CCS

With the falling costs of variable renewables and storage, it is possible that the focus of deployment of CCS will not be the power sector but rather the industry sector (e.g., applied to oil and gas extraction and refining). In that sense, it may make more sense to drive the cost reductions in CCS from non-electricity sector deployment.

The total amount of $CO_2$ emissions stored due to CCUS is provided out to 2050 from all sectors in the IEA's NZE by 2050 scenario. Since there is significant utilisation of CCUS, uptake of this technology in relevant sectors where the capture technology is similar should lead to learning in other sectors using CCUS. Therefore, we have allowed for shared cost reductions in CCS in the power sector, hydrogen production sector and included the expected CCUS uptake for abating industrial emissions based on the IEA data.

Table 3-6 Additional captured industrial emissions to be included, $MtCO_2$

| Scenario | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| **Global NZE by 2050** | 0 | 160 | 902 | 1627 |
| **Global NZE post 2050** | 0 | 0 | 0 | 160 |

*Global NZE post 2050* is based on the IEA's Sustainable Development Scenario (SDS). In this scenario net zero emissions are reached by 2070, which is a delay of 20 years, mainly in developing countries, compared to the NZE by 2050 scenario. On this basis, we have applied industrial CCUS uptake to *Global NZE by 2050* scenario, but the actual emissions stored per year are pushed out 20 years into the future.

Uptake of CCS in the power and hydrogen production sectors is determined endogenously by GALLME.

### 3.1.7 Hydrogen

In previous GenCost projections, hydrogen demand was imposed together with the type of production process used to supply hydrogen. In our current model, GALLME determines which process to use – steam methane reforming with or without CCS or electrolysers. This choice of deployment also allows the model to determine changes in capital cost of CCS and in electrolysers.

The model does not distinguish between alkaline (AE) or PEM electrolysers. That is, we have a single electrolyser technology. The approach reflects the fact that GALLME is not detailed enough to determine preferences between the two technologies which are mainly around their minimum operating load and ramp rate. There is currently a greater installed capacity of AE which has been commercially available since the 1950s, whereas PEM is a more recent technology.

The IEA have included demand for electricity from electrolysis in their scenarios. Since GALLM is endogenously determining which technologies are deployed to meet hydrogen demand, we have subtracted the IEA's demand for electricity from electrolysis from their overall electricity demand. The assumed hydrogen demand assumptions for the year 2040 are shown in Table 3-7 and include existing demand, the majority of which is currently met by steam methane reforming. The reason for including existing demand is that in order to achieve emissions reductions the existing demand for hydrogen will also need to be replaced with low emissions sources of hydrogen production.

**Table 3-7 Hydrogen demand assumptions by scenario**

| Scenario | 2040 total hydrogen demand (Mt) |
|---|---|
| **Current policies** | 137 |
| **Global NZE by 2050** | 331 |
| **Global NZE post 2050** | 150 |

### 3.1.8 Government climate policies

Carbon trading markets exist in major greenhouse gas emitting regions overseas at present and are a favoured approach to global climate policy modelling because they do not introduce any technological bias. We directly impose the IEA carbon prices. The IEA also includes a broad range of additional policies such as renewable energy targets and planned closure of fossil-based generation. The GALLME modelling includes these non-carbon price policies as well but cannot completely match the IEA implementation because of model structural differences. The IEA have greater regional and country granularity and are better able to include individual country emissions reduction policies. Some policies are difficult to recreate in GALLME due to its regional aggregation. Where we cannot match the policy implementation directly, we align our implementation of non-carbon price policies so that we match the emission outcomes in the relevant IEA scenario.

The country policy commitments included are not completely up to date. We align our scenarios with the IEA and the IEA does not include more recent announcements or changes of government policy since the IEA report was complete.

### 3.1.9 Resource constraints

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 (Table 3-8) (see Government of India, 2016, Edmonds, et al., 2013 and Hayward & Graham, 2017 for more information on sources). With the exception of rooftop PV these constraints are removed in the Global NZE by 2050.

### 3.1.10 Other data assumptions

GALLME international back coal and gas prices are based on (IEA, 2021) with prices for the Stated Policies scenario applied in all cases. The IEA tends to reduce its fossil fuel price assumptions in scenarios with stronger climate policy action. Whilst we agree that stronger climate policy action will lead to lower demand for fossil fuels, we do not think it follows that fossil prices must fall[11]. This is one of the very few areas where we do not align with all IEA scenario assumptions. Brown coal is not globally traded and has a flat price of 0.6 $/GJ.

Power plant technology operating and maintenance (O&M) costs, plant efficiencies and fossil fuel emission factors were obtained from (Aurecon, 2021) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2021) (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, 2015a) (UN, 2015b) (US Energy Information Administration, 2017a) (US Energy Information Administration, 2017b) (GWEC) (IEA, 2016a) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015).

[11] In the long run, fossil fuel prices will fluctuate due to cycles of demand and supply imbalances. However, underlying these fluctuations, prices should track the cost of production given the competitive nature of commodity markets. This relationship holds whether demand is falling or rising over the long run.

Table 3-8 Maximum renewable generation shares in the year 2050 under the Current policies scenario, except for offshore wind which is in GW of installed capacity.

| Region | Rooftop PV % | Large scale PV % | CSP % | Onshore wind % | Offshore wind GW |
|---|---|---|---|---|---|
| **AFR** | 21 | NA | NA | NA | NA |
| **AUS** | 35 | NA | NA | NA | NA |
| **CHI** | 14 | NA | NA | NA | 1073 |
| **EUE** | 21 | NA | NA | NA | NA |
| **EUW** | 21 | 2 | 23 | 22 | NA |
| **FSU** | 25 | NA | NA | NA | NA |
| **IND** | 7 | 21 | 18 | 4 | 302 |
| **JPN** | 16 | 1 | 12 | 11 | 10 |
| **LAM** | 25 | NA | NA | NA | NA |
| **MEA** | 21 | NA | NA | NA | NA |
| **NAM** | 30 | NA | NA | NA | NA |
| **PAO** | 11 | 1 | 8 | 8 | 15.5 |
| **SEA** | 14 | 3 | 32 | 8 | NA |

NA means the resource is greater than projected electricity demand. The regions are Africa (AFR), Australia (AUS), China (CHI), Eastern Europe (EUE), Former Soviet Union (FSU), India (IND), Japan (JPN), Latin America (LAM), Middle East (MEA), North America (NAM), OECD Pacific (PAO), Rest of Asia (SEA), and Western Europe (EUW)

# 4 Projection results

## 4.1 Global generation mix

The rate of technology deployment is the key driver for the rate of reduction in technology costs for all non-mature technologies. However, the generation mix is determined by technology costs. Recognising this, the projection modelling approach simultaneously determines the global generation mix and the capital costs. The projected generation mix consistent with the capital cost projections described in the next section is shown in Figure 4-1.

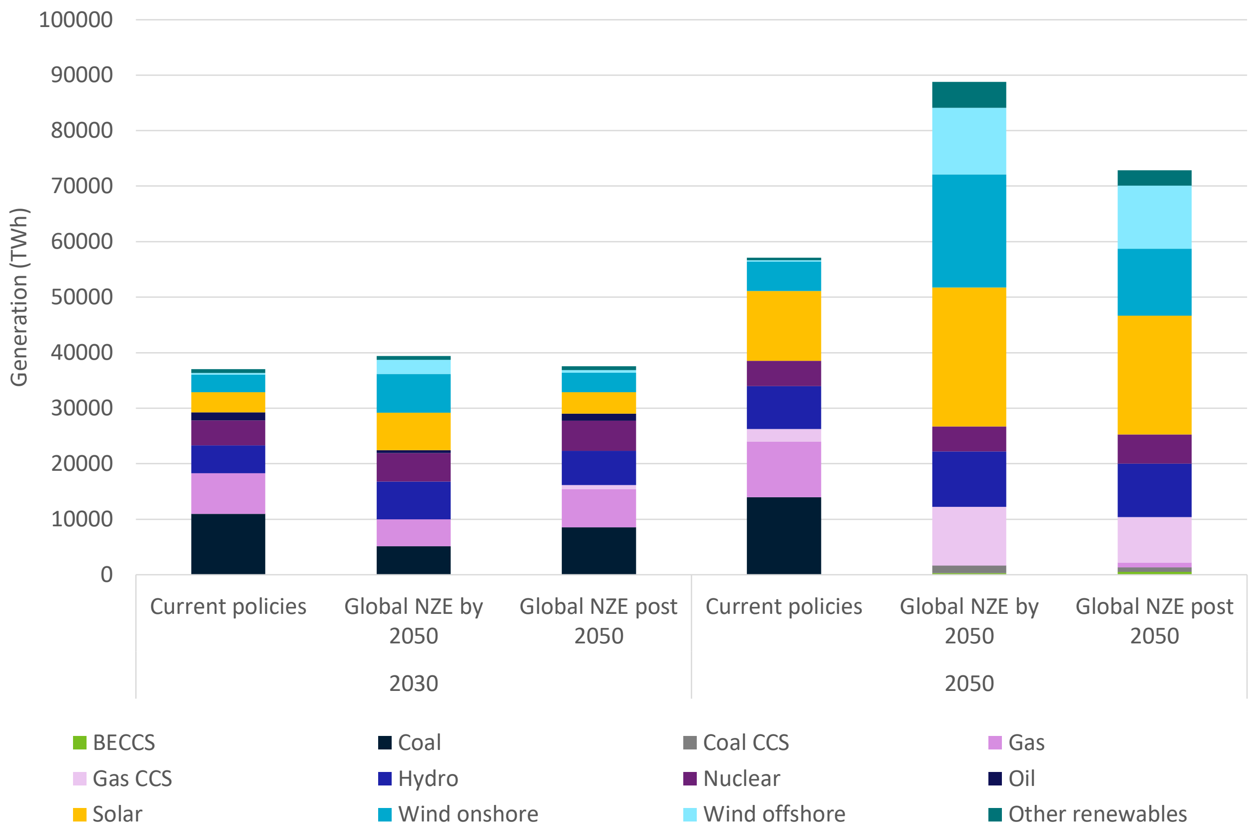


**Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario**
**The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.**

*Current policies* has the lowest electrification because it is a slower decarbonisation pathway than the other scenarios considered. However, it has the least energy efficiency and industry transformation[12]. For this reason, while it has the lowest demand by 2050 it is only slightly below *Global NZE post 2050* in 2030. Both Global NZE scenarios have high vehicle electrification and high

[12] Economies can reduce their emissions by reducing the activity of emission intensive sectors and increasing the activity of low emission sectors. This is not the same as improving the energy efficiency of an emissions intensive sector. Industry transformation can also be driven by changes in consumer preferences away from emissions intensive products.

electrification of other industries including hydrogen. However, they also have high energy efficiency and industry transformation which partially offsets these sources of new electricity demand growth. Figure 4-2 shows the contribution of each hydrogen technology to hydrogen production in each scenario.

*Current policies* has the lowest non-hydro renewable share at 33% of generation by 2050. Coal, gas, nuclear and gas with CCS are the main substitutes for lower renewables. Gas with CCS is preferred to coal with CCS given the lower capital cost and lower emission intensity. Nuclear has a proportionally higher role, at 8% by 2050 in *Current policies* compared to 5% in *Global NZE by 2050* and 7% in *Global NZE post 2050*.

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. All generation from fossil sources is with CCS accounting for 12% of generation by 2050. Offshore wind features strongly in this scenario at 16% of generation by 2050. Renewables other than hydro, biomass, wind and solar are 4% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs.

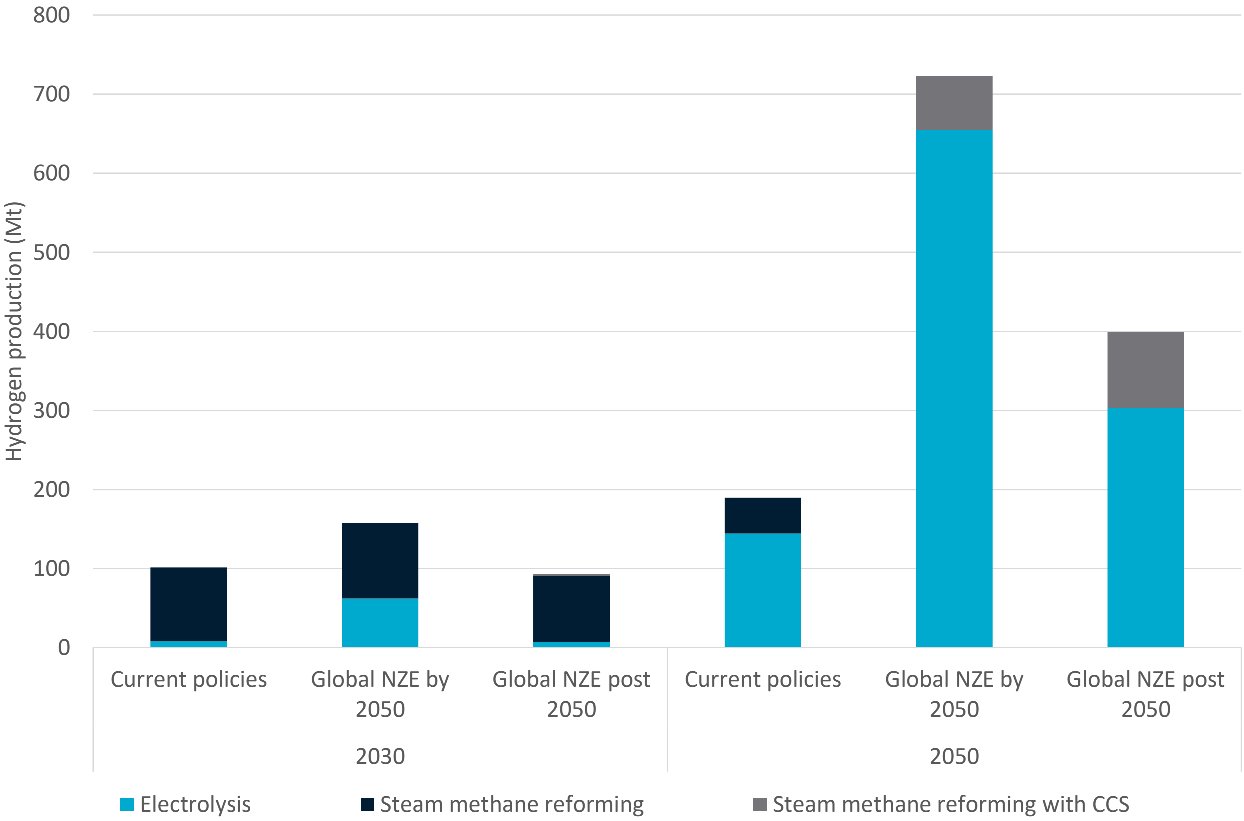


**Figure 4-2 Global hydrogen production by technology and scenario, Mt**

## 4.2 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2020-21 projections. For mature technologies, where the current costs have not changed and the assumed improvement rate is very similar, their projection pathways often overlap. The assumed annual rate of cost reduction for mature technologies is 0.35% in this report. This is slightly higher than the rate calculated in GenCost 2020-21. The method for calculating the reduction rate for mature technologies is outlined in Appendix A. Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[13].

### 4.2.1 COVID-19 and current inflationary pressures

The COVID-19 pandemic has resulted in reduced capacity in some industries which has begun to be reflected in the costs of some raw materials which are inputs to generation and storage technologies. However, the updated current cost inputs from Aurecon (2022) do not yet show any impacts. This is not surprising since our definition of current costs reflects projects already completed which were likely ordered in years prior.

Our projection model, GALLME, is able to consider temporary price bubbles but only if they are caused by excessive demand to deploy a particular technology. We do not have a specific mechanism to model the price impacts of a general tightening of supply chains. To take account of current supply chain pressures we have assumed no cost reductions for all generation projects delivered in 2022-23.

### 4.2.2 Black coal supercritical

There has been no significant change in the cost of black coal plant. The current cost is slightly lower, partially due to adjusting the previous year's estimate for inflation. The assumed rate of improvement in mature technologies over time is slightly stronger.

[13] Search GenCost at https://data.csiro.au/collections

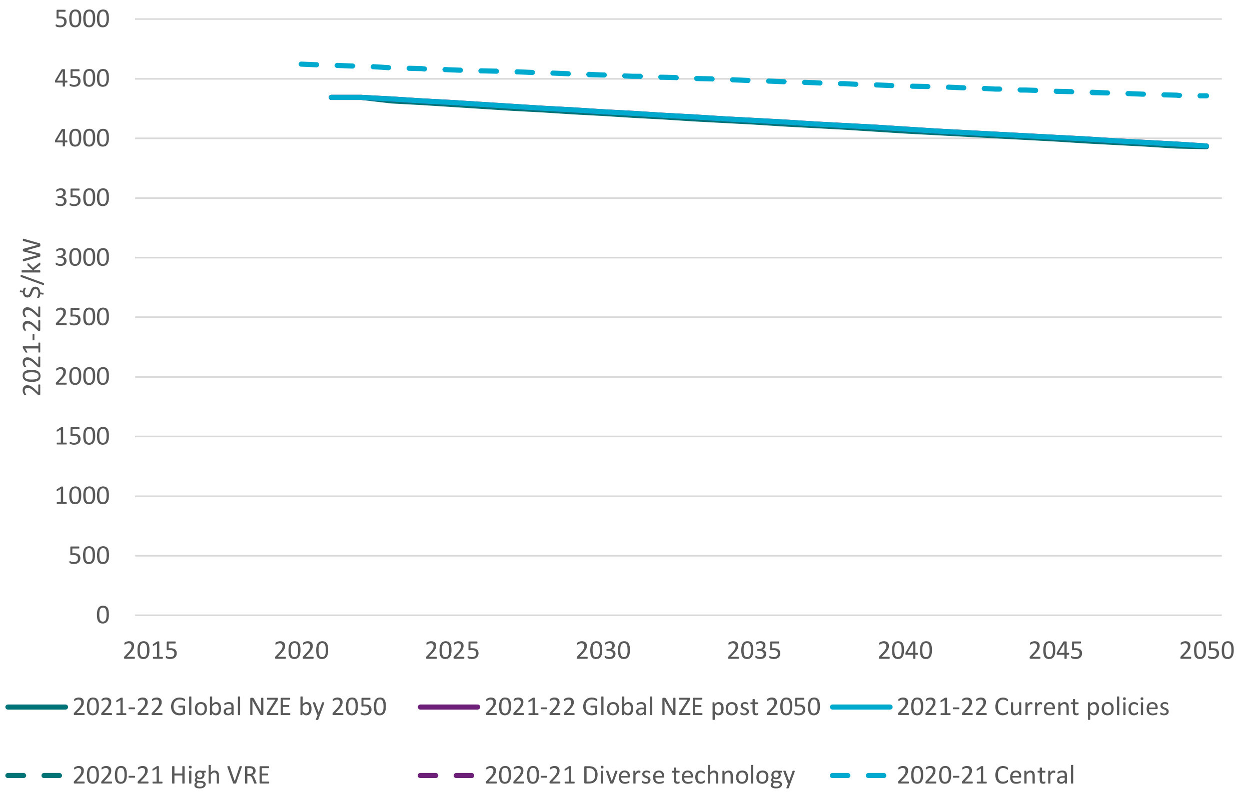


**Figure 4-3 Projected capital costs for black coal supercritical by scenario compared to 2020-21 projections**

### 4.2.3 Coal with CCS

The current cost of black coal with CCS is slightly lower than the previous years but this mainly represents an adjustment for inflation. For the mature parts of the plant the mature cost improvement rate is applied. For the CCS components, the cost reductions are a function of global deployment of gas and coal with CCS, steam methane reforming with CCS and other industry applications of CCS.

*Current policies* has no uptake of steam methane reforming with CCS in hydrogen production, but rather switches from steam methane reforming to electrolysis in the 2040s, at the same time that it is deploying gas with CCS. Black coal with CCS benefits from co-learning from deployment of the other CCS technologies, but there is only a negligible amount of generation from black coal with CCS throughout the projection period.

*Global NZE by 2050* and *Global NZE post 2050* take up CCS in hydrogen production and both gas and coal electricity generation (although gas generation with CCS is significantly more preferred). Given the scale of generation and hydrogen production required in those scenarios, together with assumed high other industry use of CCS, the total deployment of CCS technologies across all applications is high. The total deployment is slightly higher in *Global NZE by 2050.* Subsequently, that scenario experiences the largest amount of learning and cost reduction by 2050.

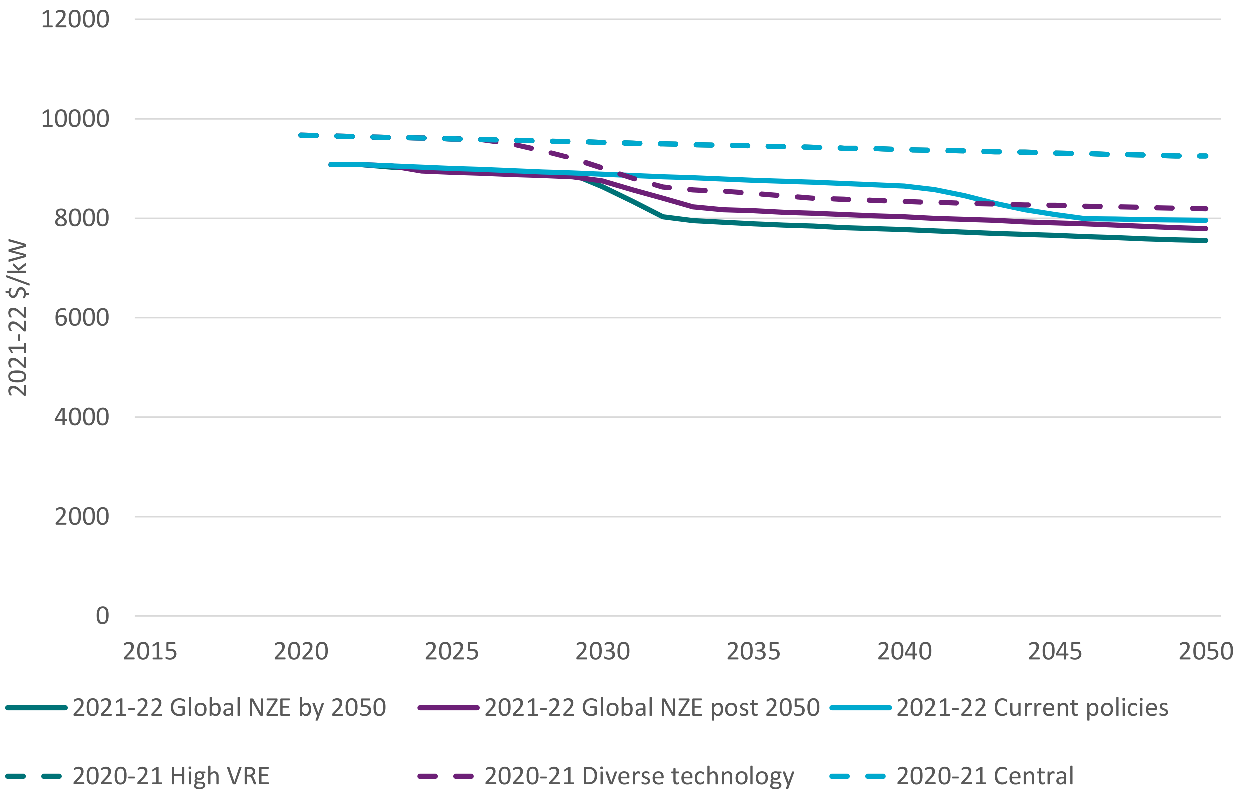


**Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2020-21 projections**

### 4.2.4 Gas combined cycle

Gas combined cycle is classed as a mature technology for projection purposes and as a result its change in capital cost is governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios. The current capital cost for gas combined cycle was updated by Aurecon (2022) and is lower than in 2020-21. Lower costs reflect current market conditions.

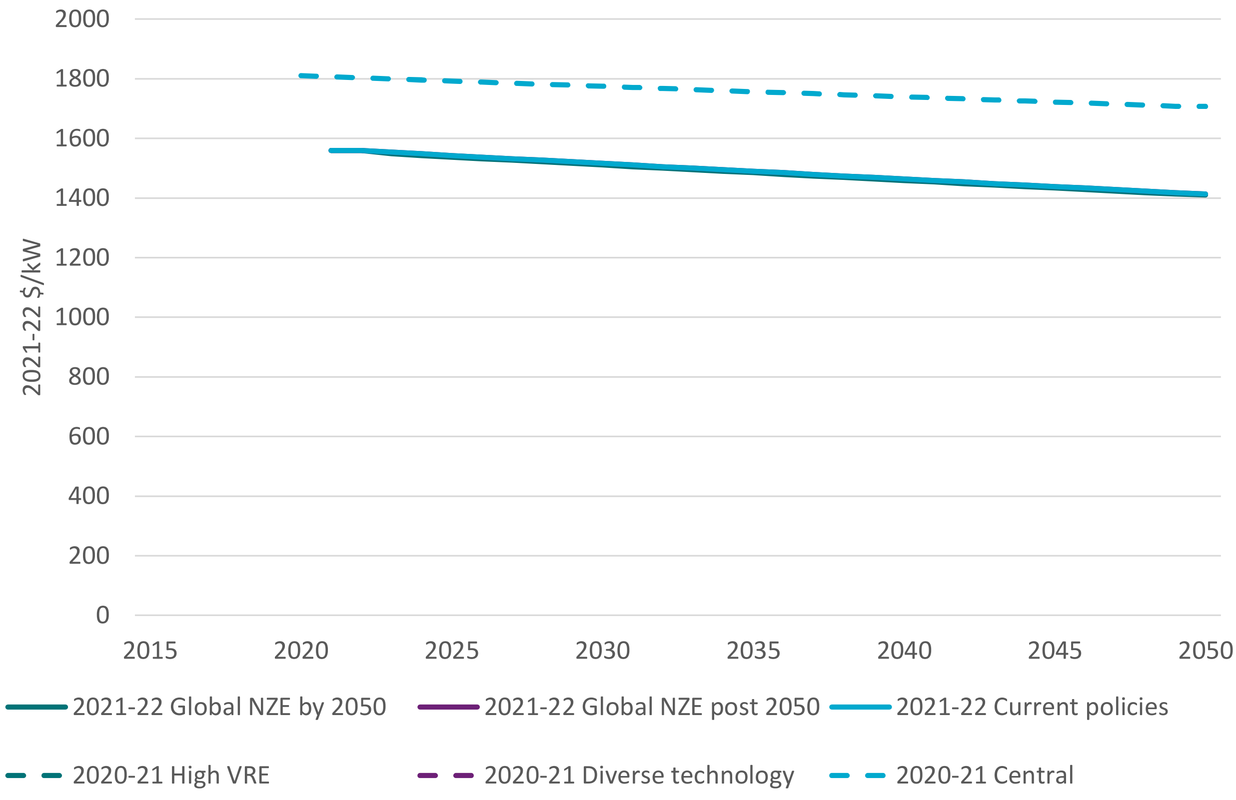


**Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2020-21 projections**

### 4.2.5 Gas with CCS

The current cost for gas with CCS has been revised downwards for the 2021-22 projections reflecting the reduction in costs of gas combined cycle plant above. The relativities between the scenarios reflect the differences in global deployment in electricity generation, hydrogen production and other industry uses of CCS. *Global NZE by 2050* has the highest total deployment of all CCS technologies, particularly in hydrogen and other non-electricity industry uses. Subsequently gas with CCS is lowest by 2050 in that scenario. Conversely CCS is highest cost in *Current policies* where CCS deployment is lowest.

*Global NZE post 2050* has the earliest reduction in costs of CCS owing to the earlier deployment of steam methane reforming with CCS in the late 2020s in that scenario leading to earlier deployment of gas with CCS. However, despite this earlier start, the level of deployment of CCS in *Global NZE by 2050* scenario overtakes *Global NZE post 2050* in the long run.

Compared to 2020-21 projections, CCS deployment is higher and affects all scenarios. This partly reflects methodology changes which have allowed for greater representation of CCS technologies across multiple industry applications.

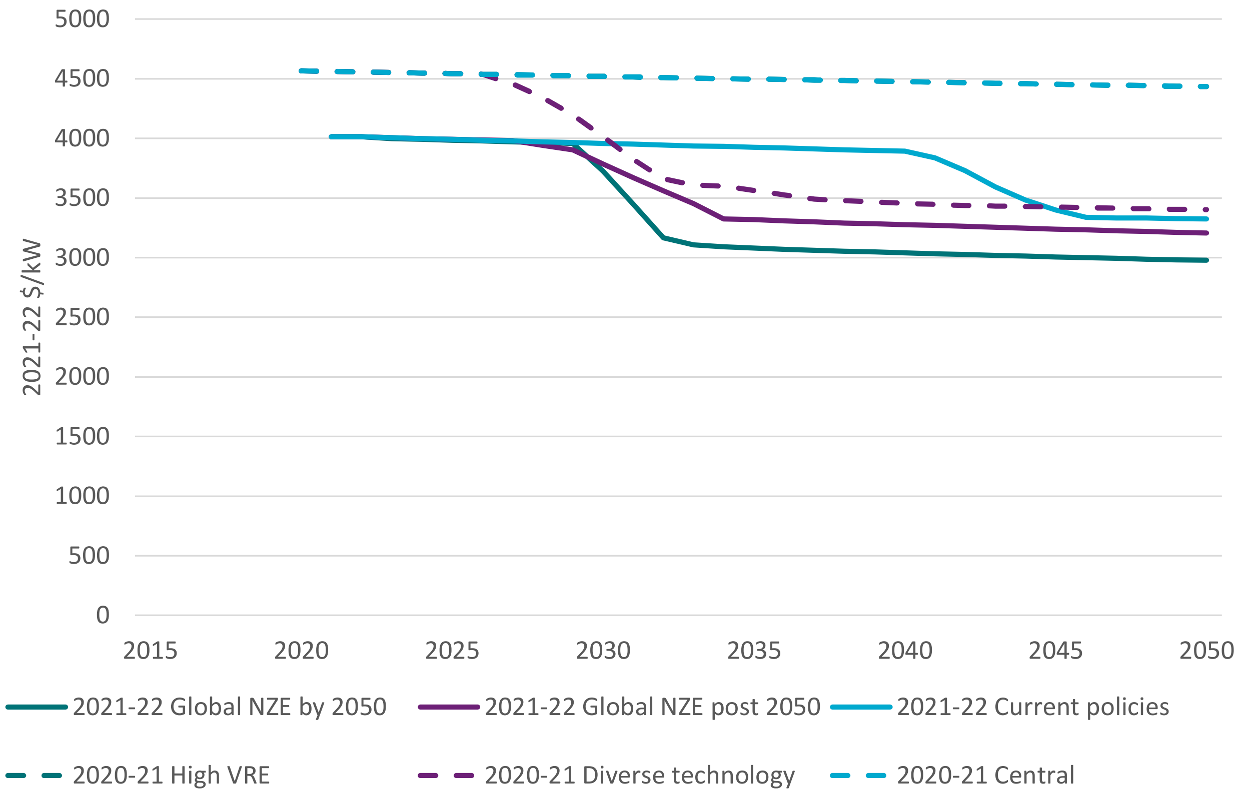


**Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2019-20 projections**

### 4.2.6 Gas open cycle (small and large)

Figure 4-7 shows the 2020-21 and updated 2021-22 cost projections for small and large open cycle gas turbines. Aurecon (2022) provides the details for the unit sizes and total plant capacity that defines the small and large sizes. Current costs are lower for both sizes. Open cycle gas is classed as a mature technology for projection purposes and as a result its change in capital costs is governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the scenarios.

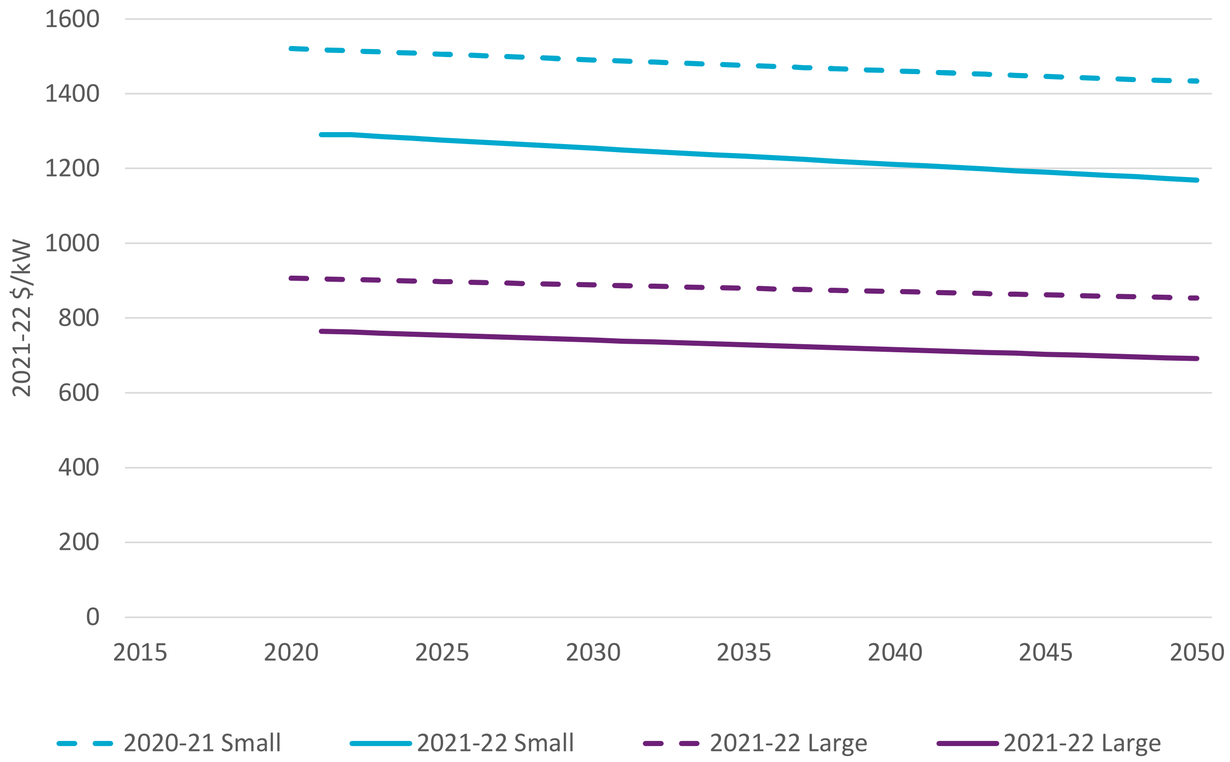


**Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2020-21 projections**

### 4.2.7 Nuclear SMR

Global commercial deployment of SMR is limited and the Australian industry does not expect any deployment here before 2030. In this context, we do not report a current cost for nuclear SMR. Instead, the projection begins from 2030. The scenarios present a divergent set of possibilities for nuclear SMR. In the Current policies scenario, the higher level of emissions means that nuclear SMR is not required. Countries are able to meet their obligations using existing commercially mature technologies.

In the Global NZE scenarios, existing commercial technologies are not sufficient to achieve the electricity sector emissions reduction. As a result, deployment of nuclear SMR proceeds and significant cost reduction are delivered through modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. Capital costs are around $7900/kW which is similar to the Diverse technology scenario in the 2020-21 projections.

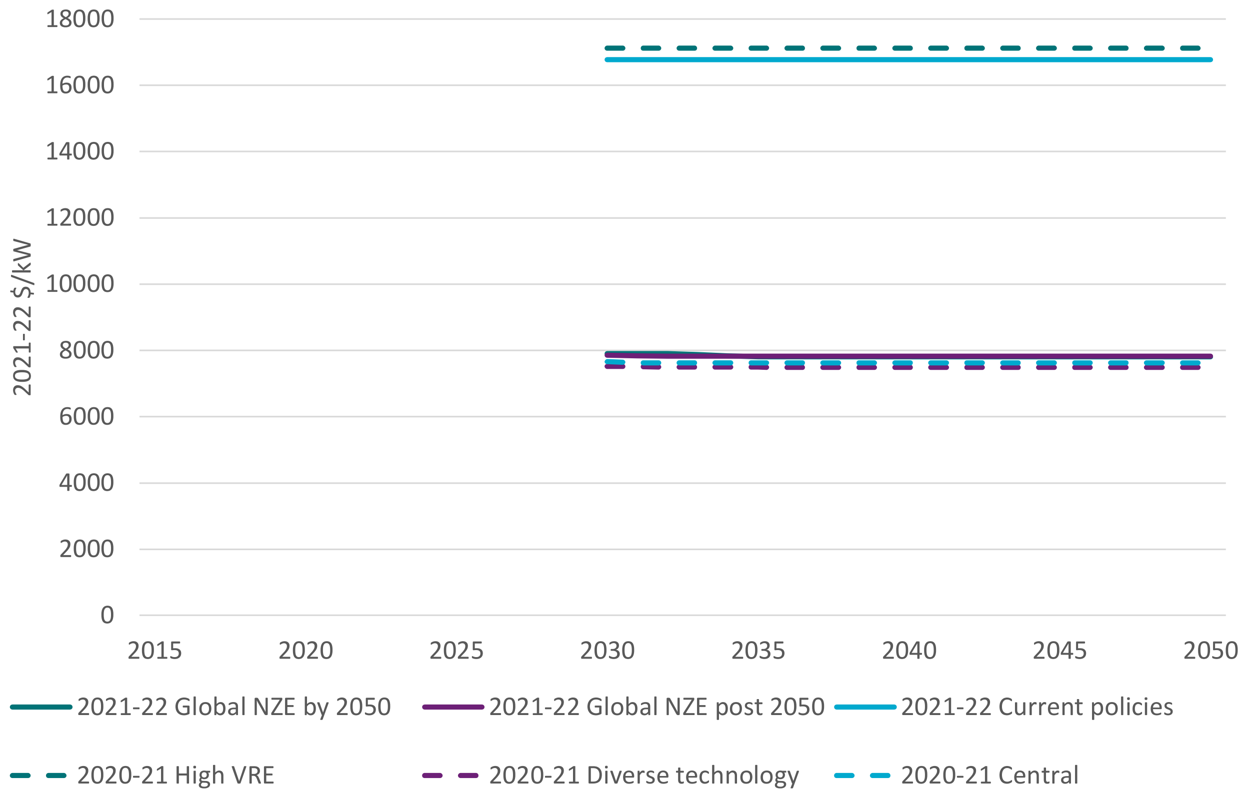


**Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2020-21 projections**

### 4.2.8 Solar thermal with 12 hours storage

The solar thermal generation technology was revised to include 12 hours storage instead of the 8 hours storage that was assumed in previous GenCost reports. 12 hours storage better reflects Australian projects in development and is likely a better competitive niche. The current capital cost of solar thermal generation was revised downwards in comparison to the 2021-22 projections (Aurecon, 2021). After we impose no change in costs in 2022-23 to reflect supply chain constraints, cost reductions proceed the fastest in *Global NZE by 2050*, followed by *Global NZE post 2050* and then *Current policies*. The deployment of solar thermal with storage is closely tied to the degree of climate policy ambition. The stronger the climate policy, the stronger the level of renewable deployment, and the greater need for technologies with longer duration storage.

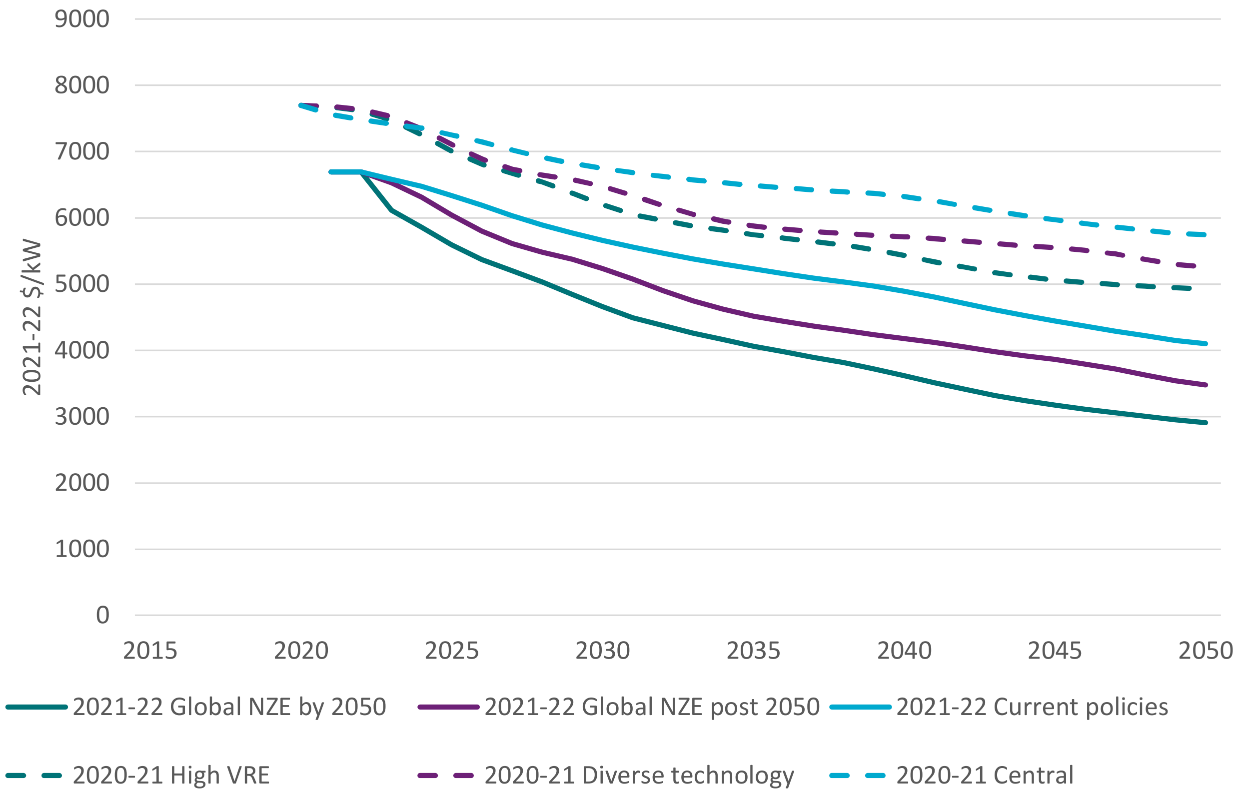


**Figure 4-9 Projected capital costs for solar thermal with 12 hours storage by scenario compared to 2020-21 projections (which were for 8 hours storage)**

### 4.2.9 Large scale solar PV

Large-scale solar PV costs have been significantly revised downwards for 2021-22. However, we pause this cost reduction in 2022-23 to reflect tighter supply chains. The broad applicability of solar PV technology to most regions of the world means that its deployment is fairly high in all global scenarios. However, cost reductions proceed faster in the Global NZE scenarios, particularly in the later 2020s. Cost reductions for *Current policies* and *Global NZE post 2050* slowly converge by 2050 reflecting different rates of deployment but similar cumulative totals by 2050. By 2050, the costs for Current policies do not converge because the total cumulative level of deployment is significantly less. The much higher cost level associated with the 2020-21 *Diverse technology* scenario was on the basis of an even lower level of large-scale solar PV deployment.

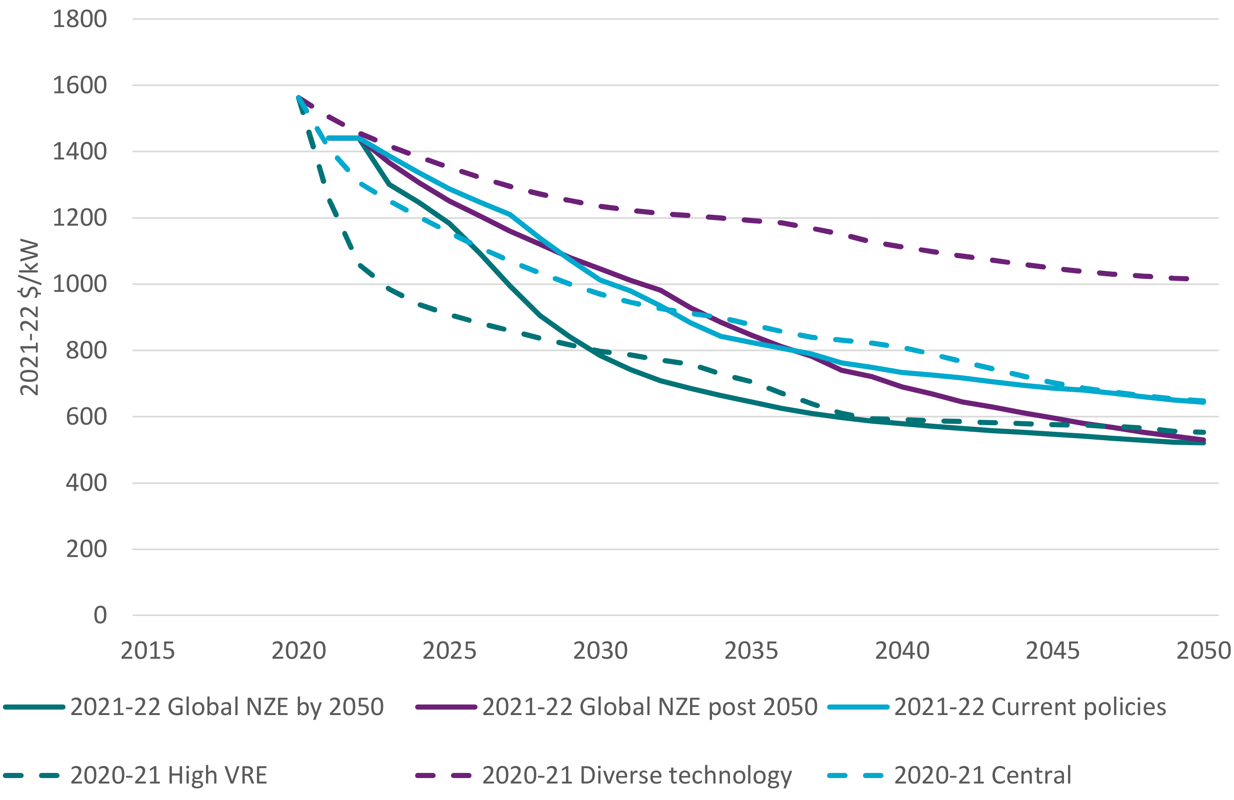


**Figure 4-10 Projected capital costs for large scale solar PV by scenario compared to 2020-21 projections**

### 4.2.10 Rooftop solar PV

The current costs for rooftop solar PV systems are lower and were sourced from historical data published by Solar Choice (7kW system)[14]. However, they note that there are significantly discounted rooftop solar PV system prices available at any time and so their data is best interpreted as a mean and may not align with the lowest cost systems available.

Rooftop solar PV benefits from co-learning with the components in common with large scale PV generation and is also impacted by the same drivers for variable renewable generation deployment across scenarios. As a result, we can observe similar trends in the rate of capital cost reduction in each scenario as for large-scale solar PV.

[14] Solar Panels Cost Data From December 2021 | Solar Choice

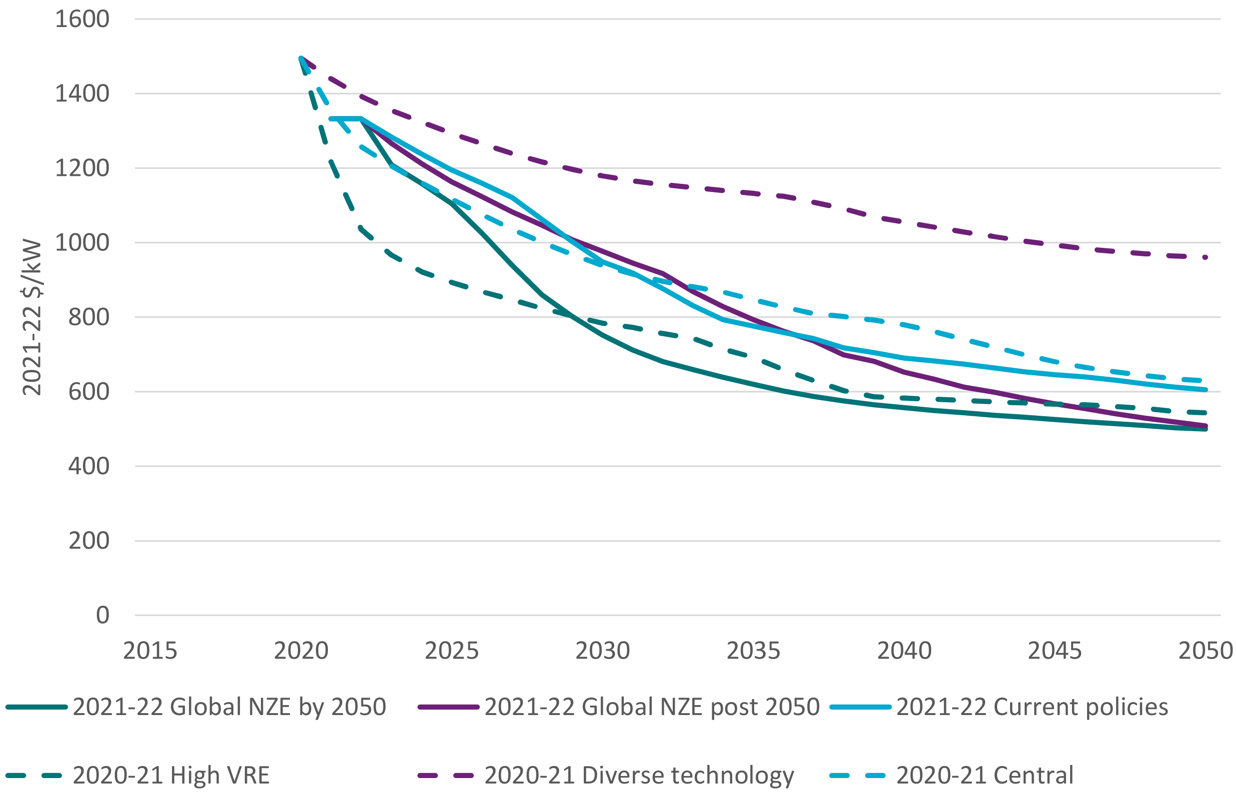


**Figure 4-11 Projected capital costs for rooftop solar PV by scenario compared to 2020-21 projections**

### 4.2.11 Onshore wind

There is a greater diversity in the forward projections of capital costs for onshore wind compared to the 2020-21 scenarios. Like other technologies, wind costs will be reduced with greater global climate policy ambition and subsequent deployment. Learning rates are also assumed to be stronger with stronger global climate policy ambition. Another factor for the greater cost reduction compared to 2020-21 projections is that we have higher global electricity generation in the 2021-22 projections and so this provides greater potential for deployment.

Wind can achieve further cost reductions by improving its capacity factor over time. Changes in the capacity factor of wind need to be factored in together with changes in capital costs to provide an overall picture of onshore wind cost reduction potential. Aurecon (2022) provides some projected changes in wind capacity factors to 2050.

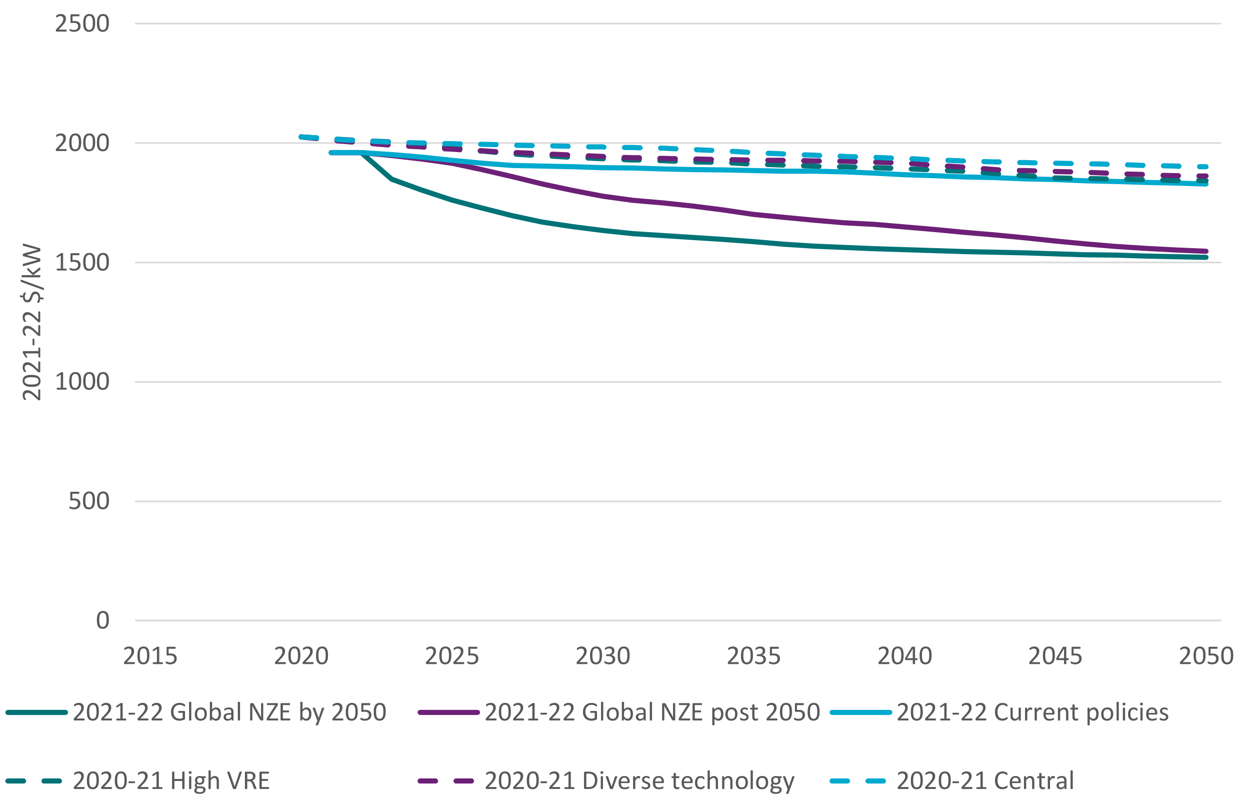


**Figure 4-12 Projected capital costs for onshore wind by scenario compared to 2020-21 projections**

### 4.2.12 Offshore wind

The 2021-22 projections have higher electricity demand than those in 2020-21. While this impacts all technologies, it has the greatest impact on offshore wind because it is a key alternative renewable technology for those countries where onshore renewable deployment will face limitations in its scale. Offshore wind plays a crucial role globally for countries with good wind resources, relatively shallow coastal depths and strong competition for land use onshore. The current capital cost of offshore wind has been revised downwards based on Aurecon (2022) and we allow for different learning rates for each scenario. Consistent with these input assumptions the projected capital cost reductions for the Global NZE scenarios are lower than the 2020-21 projections. In addition to its capital cost, offshore wind has a high potential to improve its capacity factor since very large turbines can be built without impinging on the amenity of neighbouring land uses. These high capacity factors ensure offshore wind is a competitive technology globally, contributing 16% of electricity generation by 2050 in *Global NZE by 2050* and 14% in *Global NZE post 2050*. Offshore wind has a much smaller role in the global generation mix in *Current policies*, reducing the potential for cost reduction.

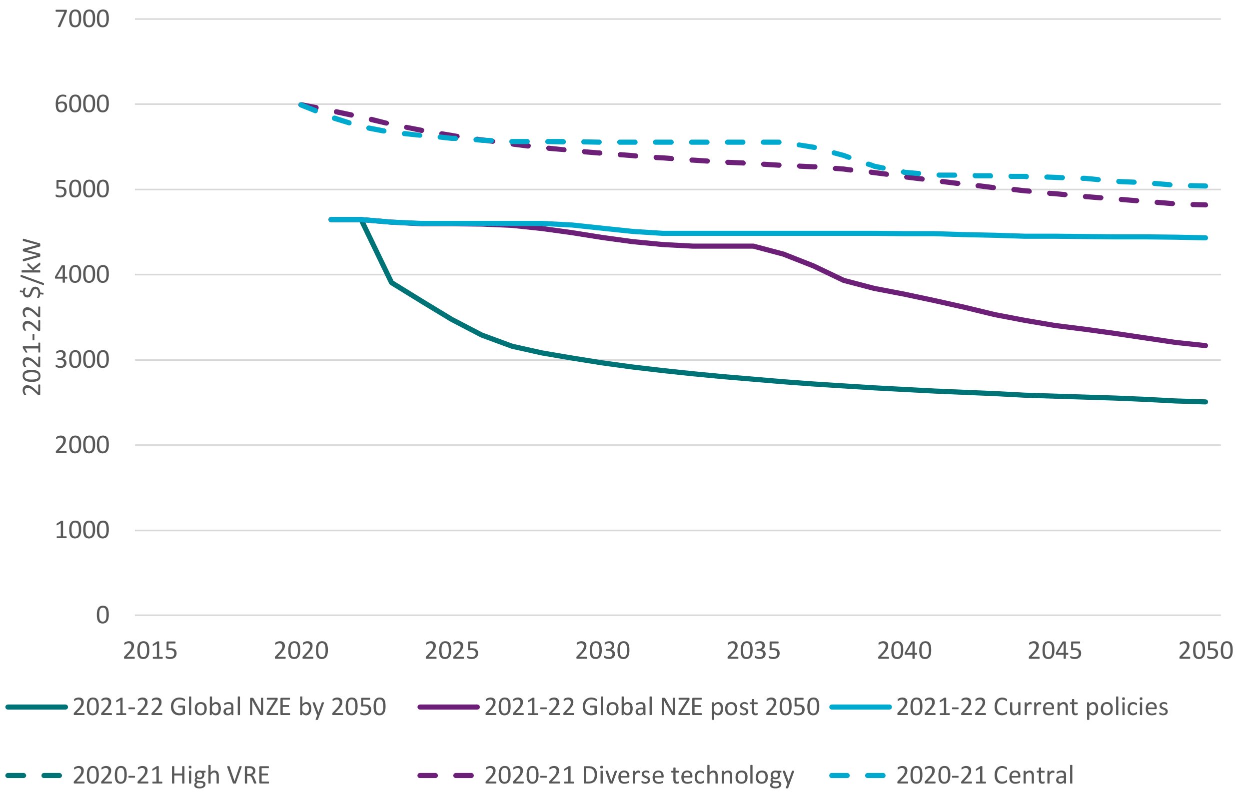


**Figure 4-13 Projected capital costs for offshore wind by scenario compared to 2020-21 projections**

### 4.2.13 Battery storage

Batteries have been able to sustain high rates of cost reduction over time and the use of different learning rates by scenario has meant the projections can reflect some uncertainty as to how well they will be able to continue to achieve historical cost reduction trends. Historical cost reductions have mainly been achieved through deployment in industries other than electricity such as in consumer electronics and electric vehicles. However, small- and large-scale stationary electricity system applications are growing globally. Under the three global scenarios, batteries have a large future role to play supporting variable renewables alongside other storage and flexible generation options and in growing electric vehicle deployment. The projected future change in total cost of battery projects is shown in Figure 4-14 (battery and balance of plant).

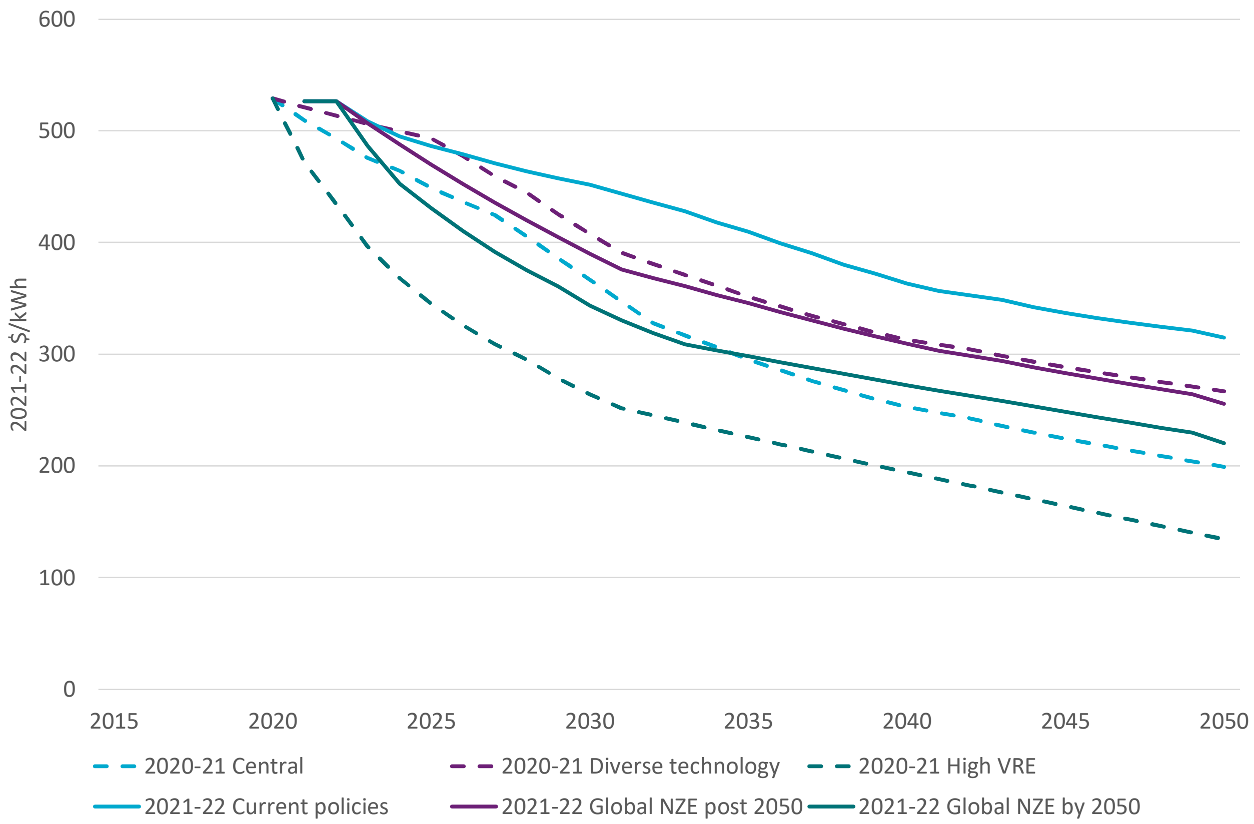


**Figure 4-14 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)**

Battery deployment is strongest in the *Global NZE by 2050* scenario reflecting stronger deployment of variable renewables, which increases electricity sector storage requirements, and stronger uptake of electric vehicles to support achieving net zero emissions by 2050. Together with an assumed high learning rate this leads to the fastest cost reduction. The remaining scenarios have more moderate cost reductions reflecting slower uptake of electric vehicles and stationary storage and assumed lower learning rates. A breakdown of battery pack and balance of plant costs for various storage durations are provided in Appendix B.

Aurecon (2022) has included current costs for small-scale batteries. They are estimated at $13000 for a 5kW/10kWh system or $1300/kWh, including installation. This is more than twice the cost of large-scale battery projects.

### 4.2.14 Pumped hydro energy storage

Pumped hydro energy storage is assumed to be a mostly mature technology with only a small proportion of site drilling/piping having the potential to improve with deployment[15]. Given the strong deployment of variable renewables in all scenarios and subsequent need for storage, this component of learning is maximised in all scenarios so that their cost trajectory is identical over time. The source of data in 2020-21 and 2021-22 is the AEMO ISP input and assumptions

[15] This improvement occurs generically for the capital cost of pumped hydro energy storage. However, any capital cost estimate is a mean of projects that may have a wide distribution of costs due to site conditions. It is possible that poorer site conditions may offset cost savings from improved drilling productivity.

workbooks – December 2020 and December 2021 respectively. Appendix B includes the costs of pumped hydro energy storage at different durations. We also assume that the costs for Tasmania 24 and 48 hour pumped hydro storage are 62% and 46%, respectively, of mainland costs. This approach is consistent with the AEMO ISP and reflects greater confidence in Tasmanian project cost estimates. The AEMO data also includes some other state differences that are not included in the national figures presented here.

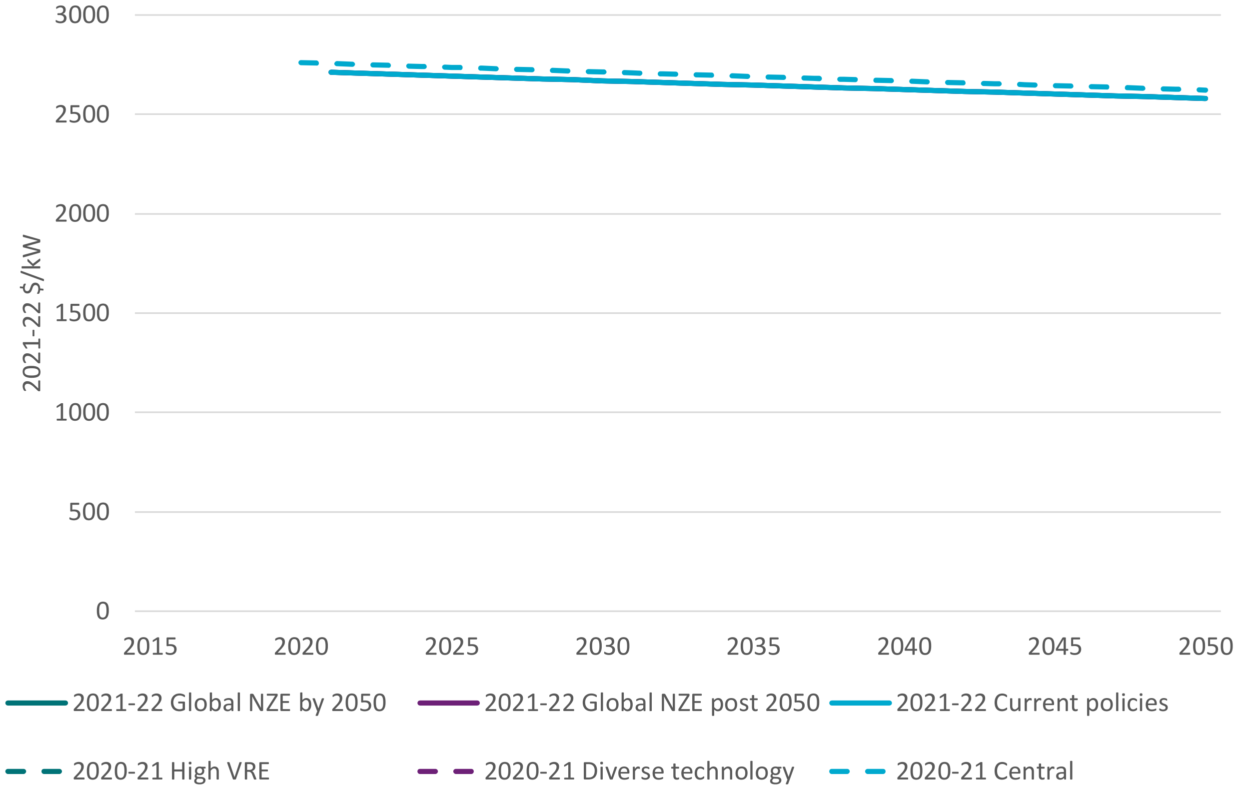


**Figure 4-15 Projected capital costs for pumped hydro energy storage (12 hours) by scenario**

### 4.2.15 Other technologies

There are several technologies that are not commonly deployed in Australia but may be important from a global energy resources perspective or as emerging technologies. These additional technologies are included in the projections for completeness and discussed below. They are each influenced by revisions to current costs. While the current cost estimate for wave and tidal/current electricity generation has not changed other technologies have. Biomass with CCS has been revised downwards to be consistent with the proportional costs of CCS in coal and gas generation. Fuel cell cost updates were sourced from Aurecon (2022).

#### Current policies

Biomass with CCS is not deployed in the *Current policies* scenario because the climate policy ambition is not strong enough to incentivise deployment. Cost reductions reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors. Fuel cell cost improvements are mainly a function of deployment and co-learning in the vehicle sector rather than in electricity generation. Neither wave nor tidal/ocean current are deployed to any significant level mainly reflecting the lack of climate policy ambition needed to drive investment in these relatively higher cost renewable generation technologies.

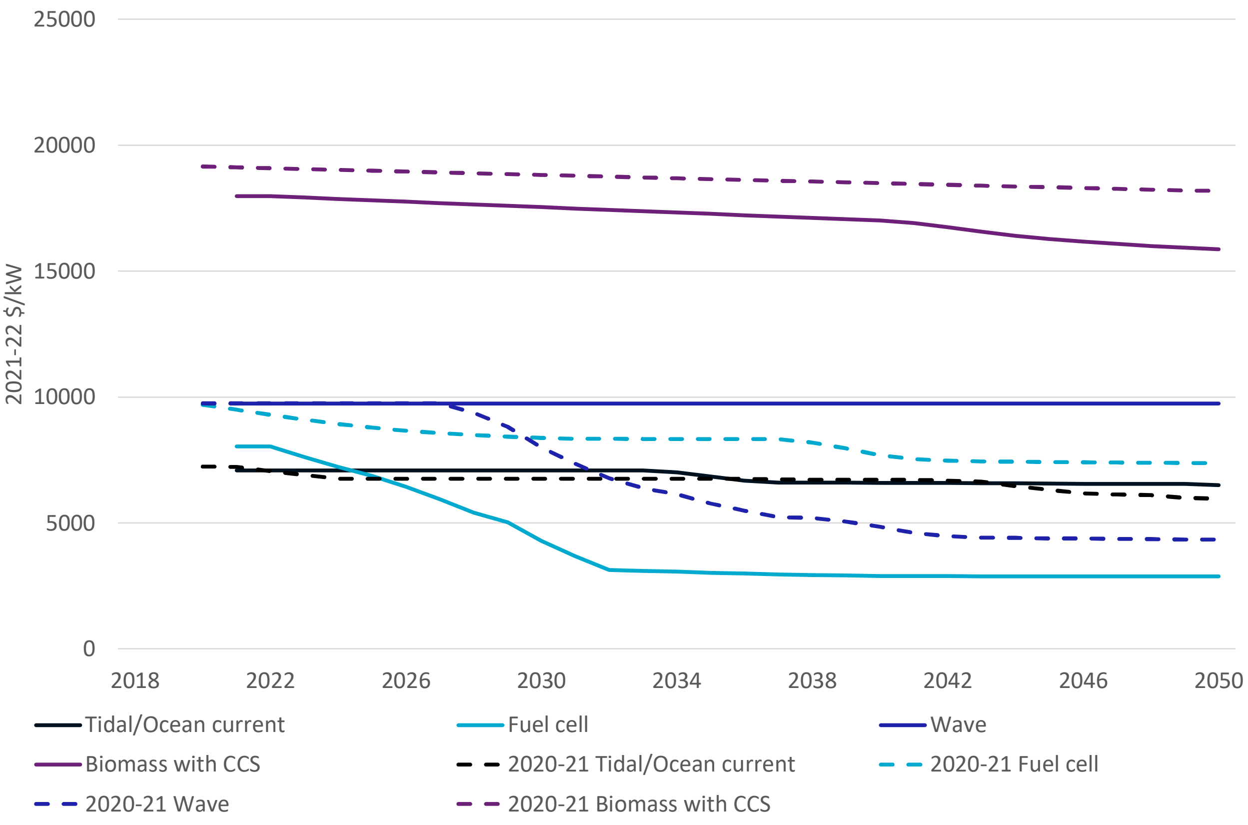


**Figure 4-16 Projected technology capital costs under the *Current policies* scenario compared to 2020-21 projections**

### Global NZE by 2050

Biomass with CCS is adopted in the *Global NZE by 2050* scenario but can only achieve learning in the CCS component of the plant. Cost reductions reflect learning from its own deployment and co-learning from deployment of CCS in other electricity generation, hydrogen and other industry sectors. Biomass with CCS is an important technology in some global climate abatement scenarios if the electricity sector is required to produce negative abatement for other sectors. However, we are not able to model that scenario with GALLME. GALLME only models the electricity sector and from that perspective alone, biomass with CCS is a relatively high-cost technology.

Fuel cell and wave generation is deployed earlier and achieves greater cost reduction than in the 2020-21 projections. This reflects higher electricity demand and more constrained solar resources in the 2021-22 modelling. Fuel cells benefit from co-learning in fuel cell vehicle deployment and this drives cost reductions in the early period. Tidal/ocean current generation is not deployed to any significant level.

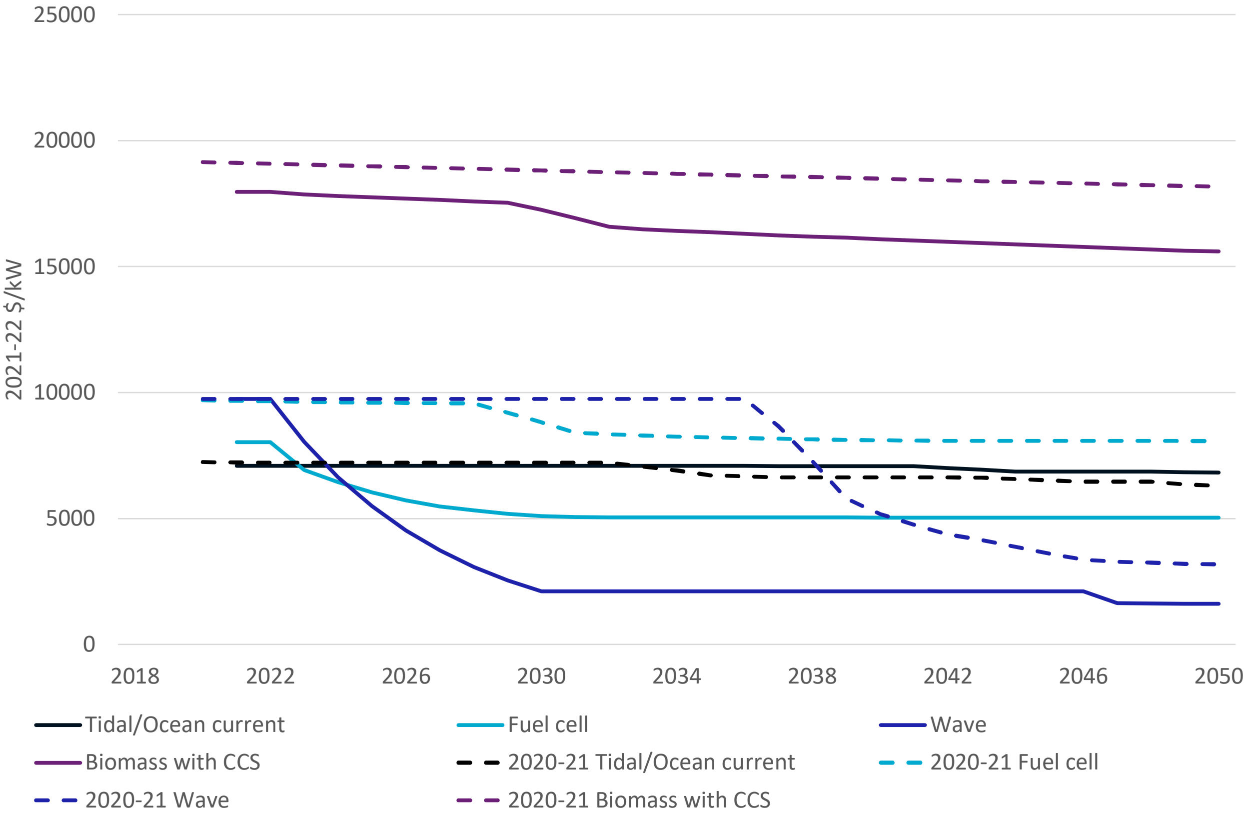


**Figure 4-17 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2020-21 projections**

### Global NZE post 2050

Biomass with CCS is deployed at about half the level of *Global NZE by 2050*. The majority of cost reductions reflect co-learning from deployment of other types of CCS generation or use of CCS in other applications. In particular, *Global NZE post 2050* has early deployment of steam methane reforming with CCS in the 2030s which brings down the cost of all CCS technologies sooner compared to other scenarios.

Similar to *Global NZE by 2050*, wave and fuel cell generation are preferred to tidal/current generation. The lower global climate policy ambition means that wave energy is not developed until later in the projection period. Fuel cell generation costs fall earlier but this reflects co-learning from deployment of fuel cells in transport rather than electricity generation applications.

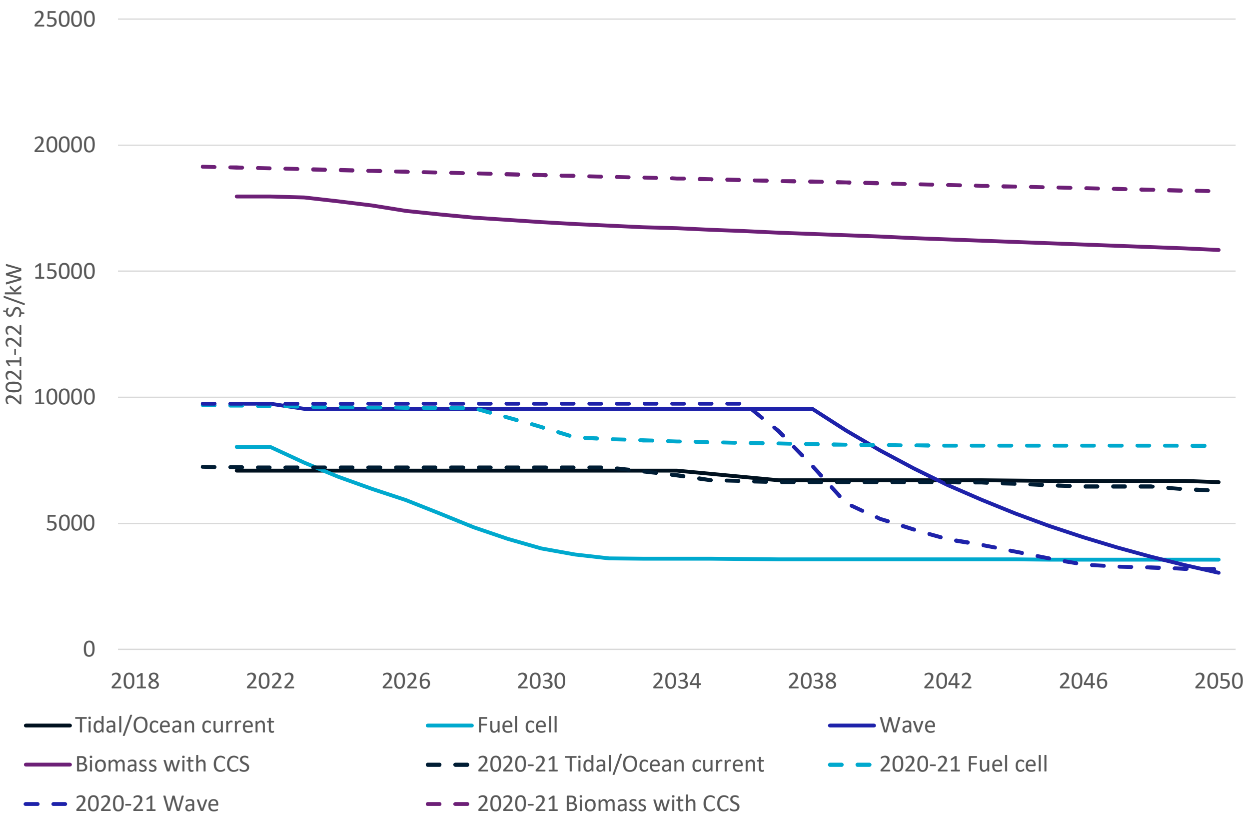


**Figure 4-18 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2020-21 projections**

## 4.3 Hydrogen electrolysers

Alkaline electrolysers are currently lower cost than proton-exchange membrane (PEM) electrolysers. However, PEM electrolysers have a wider operating range which gives them a small advantage in matching their production to low-cost variable renewable energy generation. As the costs of both technologies fall, capital costs become less significant in total costs of hydrogen production. This development could make it attractive to sacrifice some electrolyser capacity utilisation for lower energy costs (by reducing the need to deploy storage in order to keep up a minimum supply of generation). Under these circumstances, the more flexible PEM electrolysers could be preferred if their costs are low enough.

GALLME does not directly model the competition between PEM and alkaline technologies since it does not have the temporal resolution to evaluate the trade-off between capital utilisation and lower cost electricity. We model a single electrolyser technology, with current cost based on alkaline electrolyser costs and we assume PEM costs converge to alkaline costs by 2040.

The current costs applied at the starting point of the projection are for 10MW electrolysers. This scale is far smaller than we would expect to see deployed over the long term where multi-gigawatt renewable zones are being considered to supply hydrogen production hubs. No other technology in this report is presented at trial scale. We therefore adjust the scale over time in the projection to recognise electrolysers moving out of the trial stage and into full scale production. We assume full scale is 100MW and after that size they are deployed in 100MW modular units. Applying typical engineering cost scaling factors this movement to full scale accounts for around an 80% reduction in costs.

Electrolyser deployment is being supported by a substantial number of hydrogen supply and end-use trials globally and in Australia. Experience with other emerging technologies indicates that this type of globally coincident technology deployment activity can lead to a scale-up in manufacturing which supports cost reductions through economies of scale. Very low costs of electrolysers, at the bottom end of the projections here, have been reported in China. However, differences in engineering standards and operating and maintenance costs mean these are not able to be immediately replicated in other regions. They do indicate, however, a potentially achievable level of costs for other regions over the longer term.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario. Consistent with their lower global climate policy ambition, hydrogen electrolyser production is 50% lower by 2050 in *Global NZE post 2050* and 80% lower in *Current policies*.

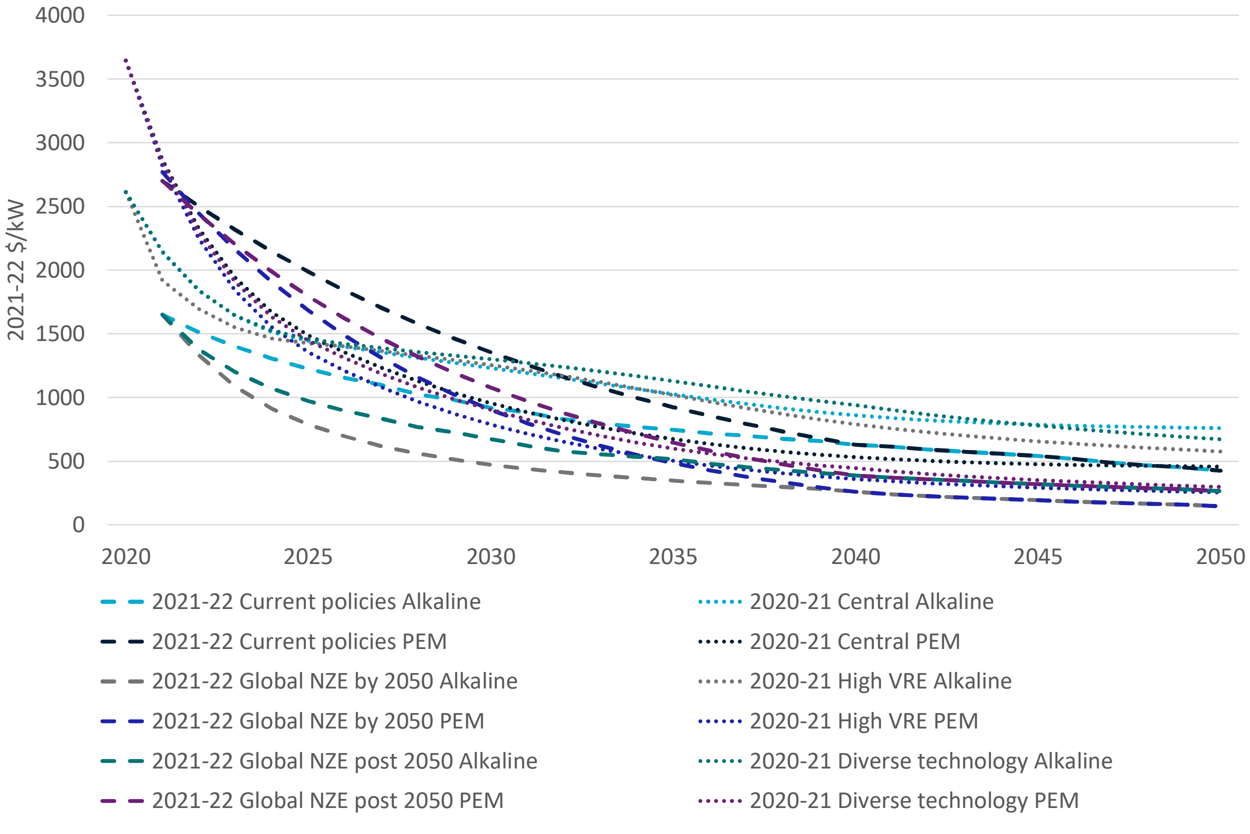


**Figure 4-19 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2020-21**

# 5 Levelised cost of electricity analysis

Levelised cost of electricity (LCOE) data is an electricity generation technology comparison metric. It is the total unit costs a generator must recover to meet all its costs including a return on investment. Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data[16]. LCOE is a simple screening tool for quickly determining the relative competitiveness of electricity generation technologies. It is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance. Furthermore, in the GenCost 2018 report and a supplementary report on methods for calculating the additional costs of renewables (Graham, 2018), we described several issues and concerns in calculating and interpreting levelised cost of electricity. These include:

- LCOE does not take account of the additional costs associated with each technology and in particular the integration costs of variable renewable electricity generation technologies
- LCOE applies the same discount rate across all technologies even though fossil fuel technologies face a greater risk of being impacted by the introduction of current or new state or commonwealth climate change policies.
- LCOE does not recognise that electricity generation technologies have different roles in the system. Some technologies are operated less frequently, increasing their costs, but are valued for their ability to quickly make their capacity available at peak times.

In Graham (2018), after reviewing several alternatives from the global literature, we proposed a new method for addressing the first dot point – inclusion of integration costs unique to variable renewables. That new method was implemented in the 2020-21 GenCost report and we update results from that method in the present report. For an overview of the method see GenCost 2020-21 Section 5.1.

To address the issues not associated with additional cost of renewables, we:

- Separate and group together peaking technologies, flexible technologies and variable technologies
- Include additional LCOE data on fossil fuel technologies which includes an additional risk premium of 5% based on Jacobs (2017).

[16] LCOE is a measure of the long run marginal cost of generation which could partly inform generator bidding behaviour in a model of the electricity dispatch system. However, in such cases, it would be expected that the LCOE calculation would be internal to the modelling framework to ensure consistency with other model inputs rather than drawn from separate source material.

## 5.1 LCOE estimates

### 5.1.1 Calculating additional costs of variable renewables

We calculate the integration costs of renewables for 2030[17], imposing a required variable renewable energy (VRE) share and running the model to determine the optimal investment to support the VRE share. In practice, although wave, tidal/current, solar thermal and offshore wind are available as variable renewable technologies, onshore wind and large-scale solar PV are the only variable renewables deployed in the modelling due to their cost competitiveness[18].

The VRE share does not include rooftop solar. The impact of rooftop solar is accounted for, however, in the demand load shape as is the impact of other customer energy resources. Customer-owned battery resources are available to support the wholesale generation sector if designated as virtual power plans (VPPs) consistent with the approach taken in the AEMO ISP.

The model covers the NEM, the South West Interconnected System (SWIS) in Western Australia (WA) and the remainder of WA. Northern Territory is not yet included in the model.

In our counterfactual or business as usual (BAU) against which integration costs are calculated, we require a minimum 50% VRE share but the model chooses around 55% in the NEM and 53% when WA is included. The share fluctuates a few percent depending on the nine weather years, 2011 to 2019, applied to the variable renewable supply traces and demand profiles. The counterfactual VRE share reflects the impact of existing state renewable targets and an already existing high VRE share in South Australia.

New South Wales, Queensland, Victoria and the SWIS are the main states of interest because Tasmania and South Australia are already dominated by renewables such that the BAU already includes all necessary investment to support very high VRE shares. However, the NEM is an interconnected system, so we are also interested in how those states support each other and the overall costs for the NEM. The VRE share is applied in each state at the same time, but individual states can exceed the share if it is economic to do so.

The BAU includes similar retirements of existing coal plants to previous AEMO ISP modelling. As we implement higher variable renewable energy shares, we must further forcibly retire coal plant as meeting the variable renewable share and the minimum load requirements on coal plant would otherwise eventually become infeasible[19]. Snowy 2.0 and battery of the nation pumped hydro projects are assumed to be constructed before 2030 in the BAU as well as various transmission expansion projects already flagged by the ISP process to be necessary before 2030. NSW gas peaking plants at Kurri Kurri and Illawarra are assumed to have been constructed. The NSW target for an additional 2 GW of at least 8 hours duration storage is also assumed to be met by 2030.

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[17] This year makes the most sense within the framework applied because there is enough time to plausibly reach high VRE shares but in the counterfactual or business as usual variable renewable shares are still expected to be at or below 60% in the larger states. In the 2040s and 2050s, much of the existing flexible capacity in the system will retire due to end of asset life and be replaced with variable renewables (see AEMO ISP and other long-term modelling). As such, most of the additional costs will already be incurred in the counterfactual.

[18] This does not preclude other types of projects proceeding in reality but is a reflection of modelling inputs in 2030.

[19] The model would be unable to simultaneously meet the minimum VRE share and the minimum run requirements of coal plant which are around 30 to 50% of rated capacity.

Annual variable renewable energy shares (VREs) are explored in the range 60% to 90%. Below 60% is not of interest because the BAU already exceeds that target. Above 90% VRE share is also not of interest because it would mean forcibly retiring other non-variable renewables such as hydro and biomass which would not be optimal for the system.

In the nine weather year counterfactuals, the model does not choose to build any new fossil fuel-based generation capacity (Figure 5-1). However, it also chooses a similar level of pumped hydro storage. The main investment response to the different weather is to build up to 3.2GW more or less of wind, 1.6GW more or less of solar PV capacity and 1.4GW more or less of large-scale batteries (VPP capacity is fixed). The capacities shown have been compared with the AEMO ISP 2030 capacity projections. The NEM coal retirements to 2030 are aligned with Step Change (December 2021 release) but the overall demand and renewable generation is lower. Wind capacity is more clearly preferred over solar PV by 2030. This preference is stronger in the ISP[20]. The NEM and WA total variable renewable share is 55% to 57%. The announced complete closure of the Muja coal generator by 2029 in WA was not able to be included in this release[21].

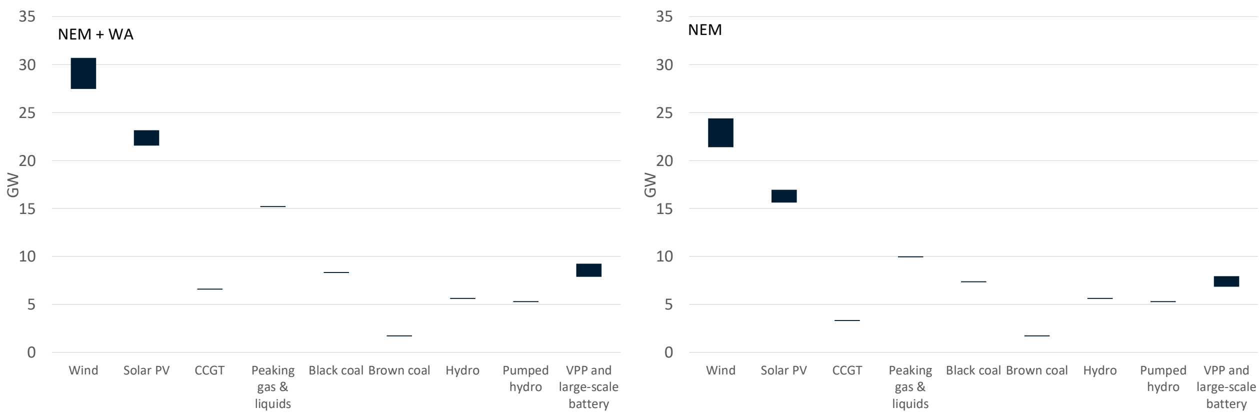



**Figure 5-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia and NEM only**

The costs of VRE share scenarios were compared against the same counterfactual weather year to determine the additional integration costs of achieving higher VRE shares. We use the maximum cost across all weather years as the resulting integration cost on the basis that the maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation.

The results, shown in Figure 5-2, include storage, transmission and synchronous condenser costs. Synchronous condensers are one of several technologies that can be used replace lost inertia from mainly fossil fuel-based generation when it retires to make way for the higher VRE shares.

As expected, the results indicate that additional costs increase with higher VRE shares. There have been several changes relative to the 2020-21 analysis. As the model has been updated to be consistent with AEMO ISP data sets, transmission costs have increased. Storage costs have not increased and there has been a stronger commitment to building storage in the BAU, particularly

[20] This outcome only relates to 2030 and large-scale generation. When rooftop solar PV is included and as solar PV costs fall faster in the projections, a closer share of wind and solar PV is likely to emerge in the long run as reflected in the global generation mix in Figure 4-1

[21] Some of this capacity remains in this modelling. This policy change will be included in the next GenCost release.

in NSW. As a result, NSW has no additional storage requirements by 2030 whereas in previous analysis this was a significant part of additional renewable integration costs. Storage needs are now strongest in the SWIS and Queensland.

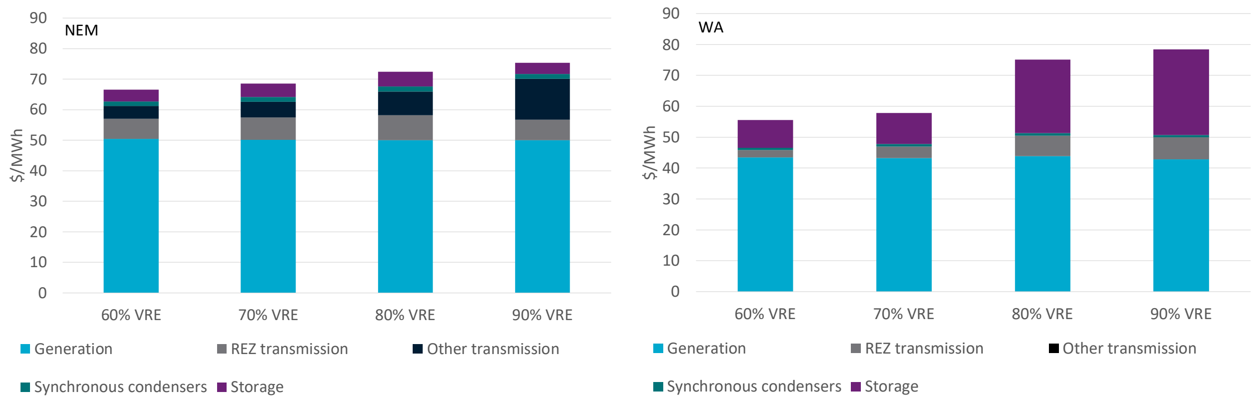



**Figure 5-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in NEM and WA in 2030**

Transmission costs include the transmission costs to connect Renewable Energy Zones (REZs) to the grid and *Other transmission* which includes state interconnectors and general expansion of existing lines that connect transmission zones within states. REZ expansion costs appear to be required at similar levels for each additional 10% increase in VRE share and in each state. Other transmission expenditure is a greater share of costs in these updated results, increasing over time.

Besides increases in transmission costs, the greater emphasis on other transmission expenditure is a reflection of the diversity value of multiple wind sources which is not captured through simple analysis of a single project. Wind resources are less correlated with each other than solar and this reduces the requirements for storage relative to systems with a higher solar share. However, increased transmission capacity between states and transmission zones is crucial in linking up non-coincident wind generation sources. There is greater transmission expenditure in New South Wales and Victoria reflecting their central positions in the NEM and access to pumped hydro storage.

The SWIS and other WA systems do not currently have major storage projects mandated and the remote locality of each system means they are unable to use other transmission expenditure to significantly diversify renewable generation sources to reduce storage needs. WA therefore has relatively higher expenditure on storage offset by lower transmission costs. Queensland and Victoria have the next greatest storage needs reflecting less developed storage in the BAU compared to New South Wales.

Additional expenditure on synchronous condenser capacity is required in most states and increases moderately with VRE share. Higher VRE share leads to the retirement of fossil fuel-based capacity that otherwise supplies most of system inertia.

Higher or lower costs in different states or regions are averaged out at the aggregate level for the NEM and WA. The cost of REZ transmission expansions adds around \$6/MWh to \$8/MWh, as the VRE share increases from 60% to 90%. Synchronous condensers costs are low at between \$1.0/MWh to \$1.2/MWh increasing moderately with VRE share. Other transmission adds \$3.8 to \$10.0/MWh with costs accelerating with VRE share. Storage adds \$6.4 to \$8.4/MWh.

### 5.1.2 Variable renewables with and without integration costs

The results for the additional costs for increasing variable renewable shares are used to update and extend our LCOE estimates. We expand the results for 2030 to include a combined wind and solar PV category for different VRE shares. Integration costs to support renewables are estimated at \$16 to \$28/MWh depending on the VRE share (Figure 5-4).

Onshore wind and solar PV without transmission or storage costs are the lowest cost generation technology by a significant margin. Offshore wind is higher cost but competitive with other alternative low emission generation technologies and its higher capacity factor could result in lower integration costs. Integration costs have only been calculated for onshore wind in this report given it remains the lowest cost form of wind generation.

The additional integration costs associated with increasing variable renewable generation from onshore wind and solar PV are presented for 2030. The analysis confirms that when integration costs are included variable renewables remain the lowest cost new-build technology. The next lowest cost technology is black coal generation but only if it could be financed at a rate that does not include climate policy risk. Of the low emissions technologies, solar thermal and offshore wind generation are the next most competitive.

### 5.1.3 Peaking technologies

The peaking technology category includes two sizes for gas turbines, a gas reciprocating engine and a hydrogen reciprocating engine. Fuel comprises the majority of costs, but the lower capital costs of the larger gas turbine make it the most competitive. Reciprocating engines have higher efficiency and consequently, for applications with relatively higher capacity factors and where a smaller unit size is required, they can be the lower cost choice.

Hydrogen reciprocating engines are higher cost at present. However, their costs are expected to fall over time. Providing the hydrogen is made from low emission sources, this technology is a low emission option for provide peaking services.

### 5.1.4 Flexible technologies

Black coal, brown coal and gas-based generation technologies fall into the category of technologies that are designed to deliver energy for the majority of the year. They are the next most competitive generation technologies after variable renewables (with or without integration costs). It is difficult to say which fossil fuel is more competitive as it depends very much on the price outcome achieved in contracts for long term fuel supply and the investor’s perception of climate policy risk.

New fossil fuel generation faces the risk of higher financing costs over time because all states and the commonwealth have either legislated or have aspirational net zero emission by 2050 targets. We address these risks in the cost estimations by including a separate estimate which assumes a

5% risk premium on borrowing costs[22]. Natural gas-based generation is less impacted by the risk premium because of its lower emission fuel, higher thermal efficiency (in combined cycle configuration only) and lower capital cost.

We do not include a risk premium for low emission flexible technologies. From 2030, solar thermal with 12 hours storage is the most competitive of this group. Gas with CCS and small modular reactor (SMR) nuclear are the next most competitive. Achieving the lower end of the nuclear SMR range requires that SMR is deployed globally in large enough numbers to bring down costs available to Australia. Lowest cost gas with CCS is subject to accessing gas supply at the lower end of the range assumed (see the appendices for assumptions).

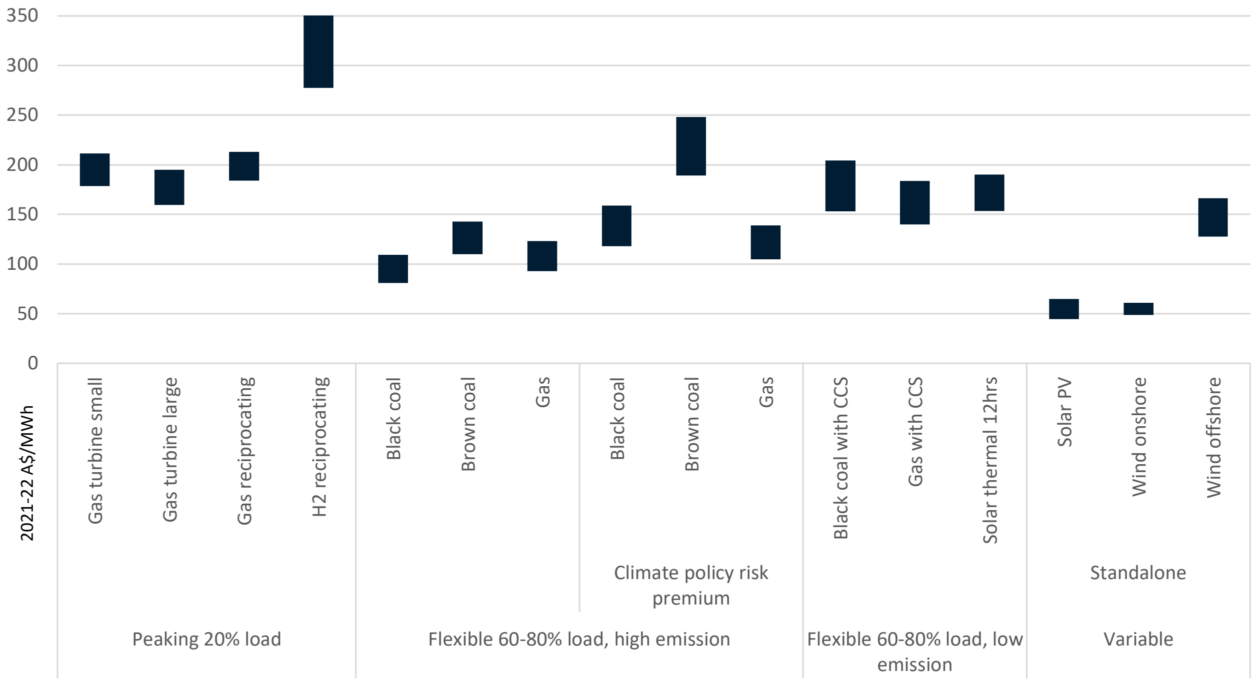



**Figure 5-3 Calculated LCOE by technology and category for 2021**

[22] This risk premium has been applied in previous studies (e.g., the 2017 Finkel review modelling) but may not adequately represent the present difficulty in obtaining finance for fossil fuel projects.

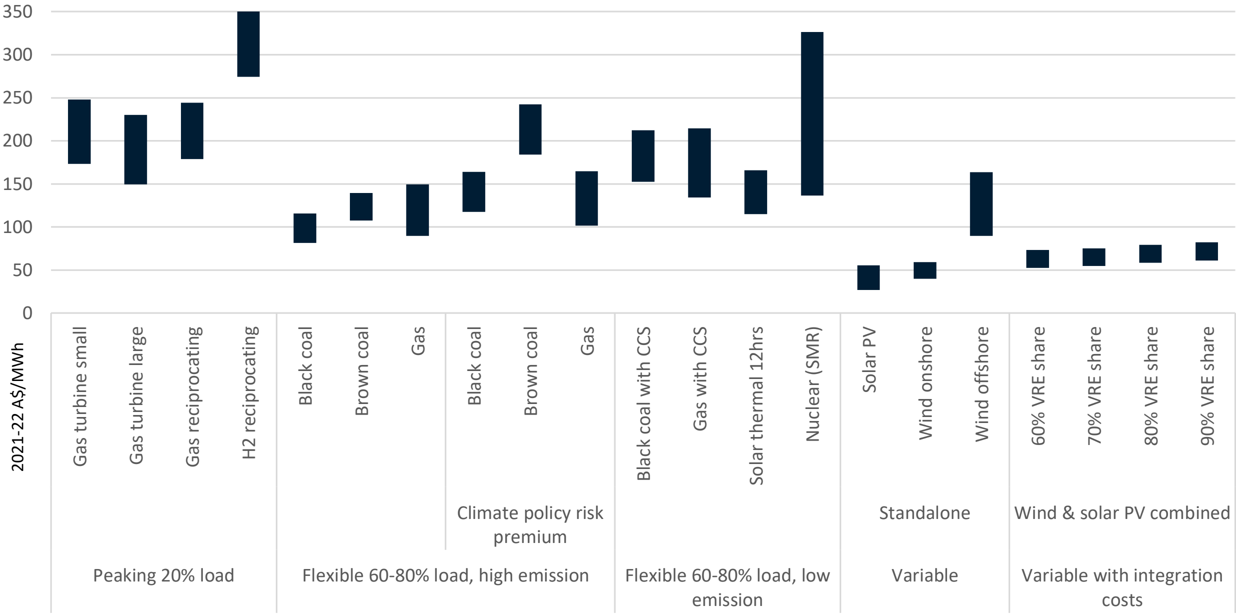



**Figure 5-4 Calculated LCOE by technology and category for 2030**

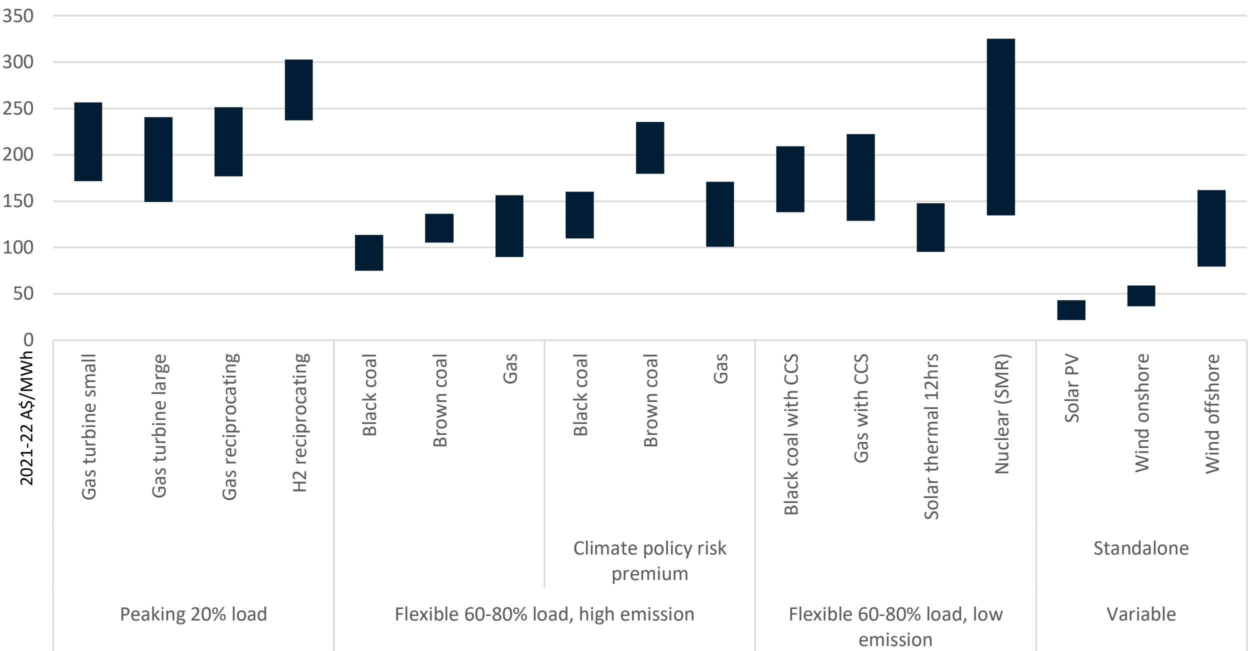



**Figure 5-5 Calculated LCOE by technology and category for 2040**

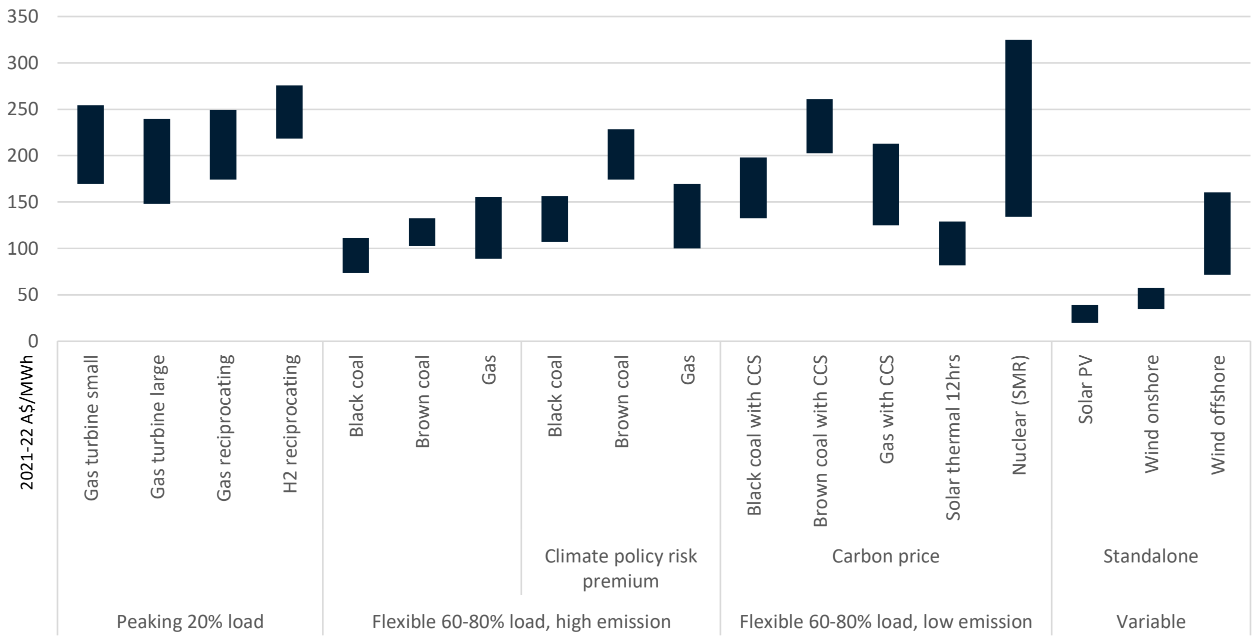



**Figure 5-6 Calculated LCOE by technology and category for 2050**

## 5.2 Storage requirements underpinning variable renewable costs

In both formal and informal feedback, a common concern is whether GenCost LCOE calculations have accounted for enough storage or other back-up to deliver a steady supply from variable renewables. Ensuring all costs are accounted for is important when comparing costs with other low emission technologies such as nuclear SMR which can provide steady supply. Intuitively, high variable renewable systems will need something else to supply electricity for extended periods when variable renewable production is low. This observation might lead some to conclude that the system will need to build the equivalent capacity of long duration storage or other flexible and peaking plant (in addition to the original variable renewable capacity). However, such a conclusion would substantially overestimate storage capacity requirements.

Variable renewables have a low capacity factor, which means the full capacity is only generating for a fraction of the year (e.g., 20% to 40%). As a result, to deliver the equivalent energy of a coal generator, the system needs to install around three times the variable renewable capacity. If system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has six times the capacity needed when coal is deployed. For a number of reasons this scale of capacity development is not necessary.

The most important factor to remember is that while we are changing the generation source, maximum demand has not changed. Maximum demand is the maximum load that the system has to meet in a given year. It typically occurs during heat waves in warmer climates (which is most of Australia) and in winter during extended cold periods in cooler climates (e.g., Tasmania). The combined capacity of storage, peaking and other flexible generation only needs to be sufficient to meet maximum demand. In a high variable renewable system, maximum demand will be significantly lower than the capacity of variable renewables installed. So instead of installing storage on a kW per kW basis, to ensure maximum demand is met, we only need to install a fraction of a kW of storage for each kW of variable renewables. The exact ratio depends on two other factors as well.

The first is that we are very rarely building a completely new electricity system (except in new off grid areas). Existing electricity systems will have existing peaking and flexible generation. This reduces the amount of new capacity that needs to be built. This is as true for coal generation or any other new capacity as it is for variable renewable generation. All new capacity relies on being supported by existing generation capacity to meet demand.

The second factor is that, as the variable renewable generation share increases, summer or winter peaking events may not represent the most critical day for back-up generation. For example, during a summer peaking event, solar PV generation is high and consequently storages are relatively full and available to deliver into the evening peak period. A more challenging period for variable renewable system might be on a lower demand day when cloud cover is high and wind speed is low. These days with low renewable generation and low charge to storages could see the greatest demands on storage, peaking and other flexible capacity. As such it may be that the low demand level on these low renewable generation days is a more important benchmark in setting the amount of additional back-up capacity required.

The modelling approach applied accounts for all of these factors across nine historical weather years. The result we find is that, in 2030, the NEM needs to have 0.20kW to 0.34kW storage capacity for each kW of variable renewable generation installed. Showing the most extreme case of 90% variable renewable share for the NEM, Figure 5-7 show the maximum annual demand, demand when renewable generation is lowest, storage capacity, peaking capacity, other flexible capacity and total variable renewable generation capacity.

The data shows that:

- Demand at the point of lowest renewable generation[23] is substantially lower than maximum demand
- Existing and new flexible capacity is slightly lower than maximum demand indicating some variable renewable generation is available at peak demand (across the nine weather years examined). Flexible capacity exceeds demand at minimum renewable generation.
- The required existing and new flexible capacity to support variable renewables is a fraction of total variable renewable capacity.

[23] Calculated as sum of non-coincident NEM state demand.

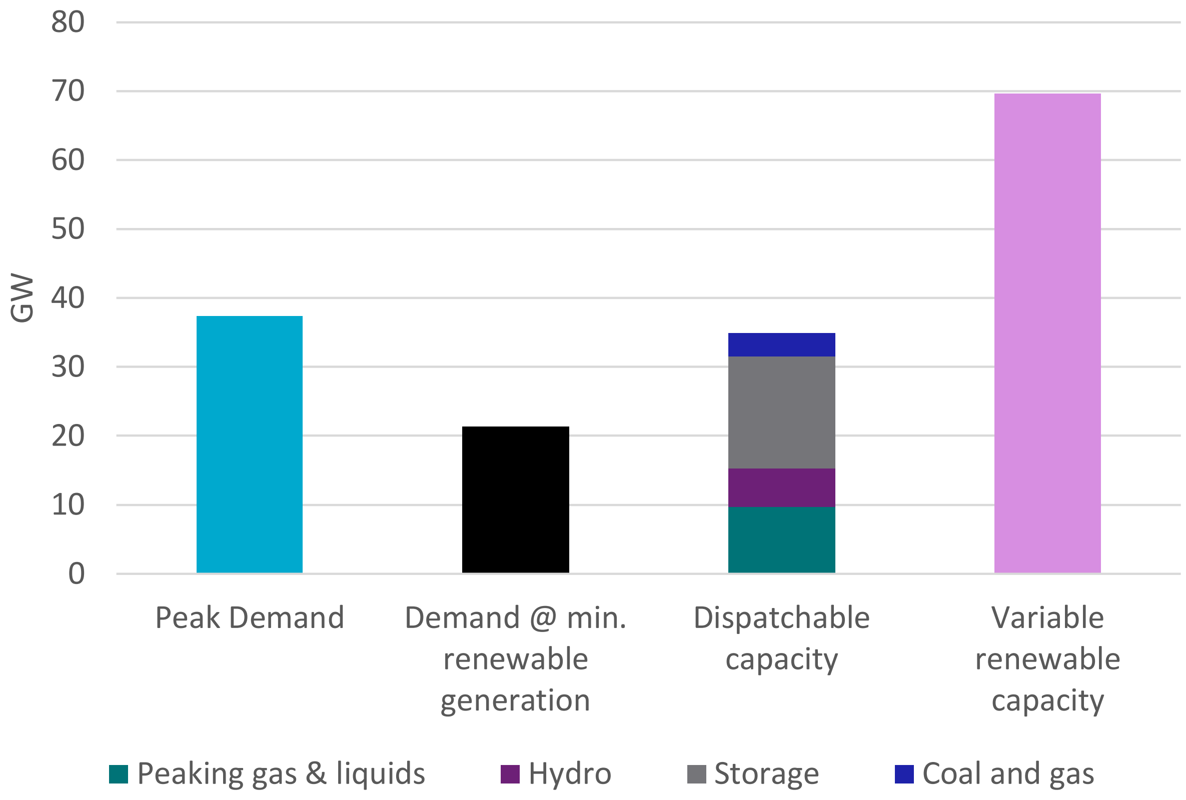



**Figure 5-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share**

# Appendix A Global and local learning model

## 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, 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:

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

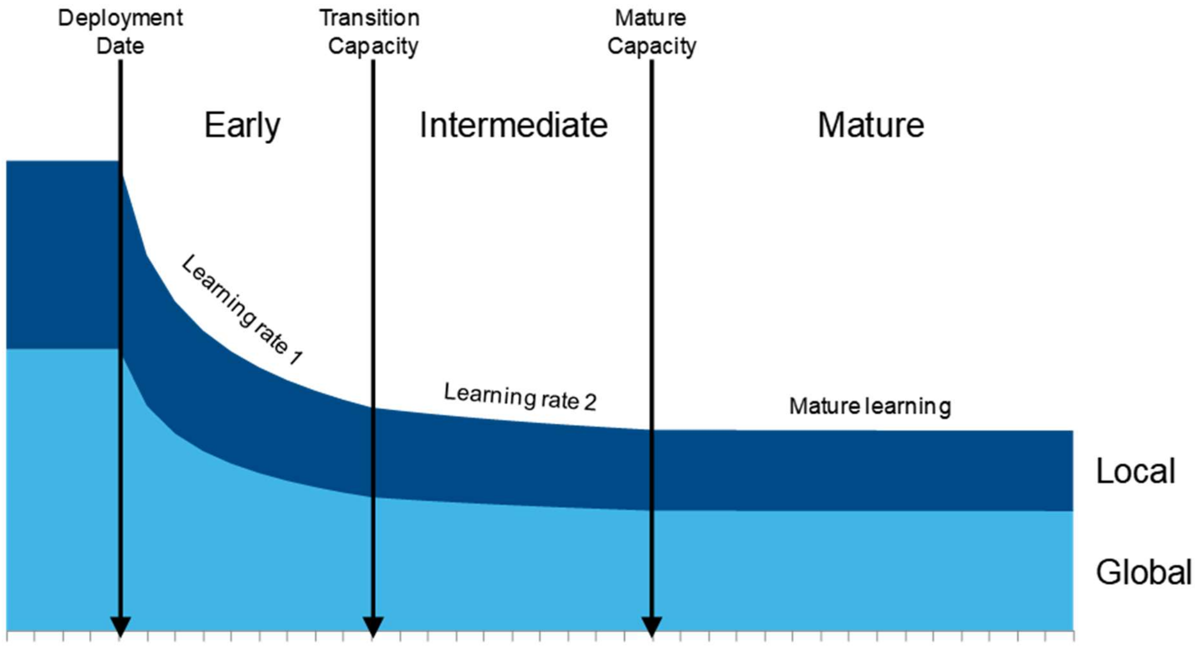
or equivalently $\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$

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 (15–20%), which reduces once the technology has at least a 5% market share and is considered to be at the intermediate stage (to approximately 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

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 GALLM models 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 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 year to 2050.

### A.1.3 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: - 0.35%. This value has been applied as an annual capital cost reduction factor to mature technologies and to operating and maintenance costs.

# Appendix B Data tables

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

The year 2021 is mostly sourced from Aurecon (2022) and is aligned to the end of that calendar year or the middle of the 2021-22 financial year.

## Apx Table B.1 Current and projected generation technology capital costs under the *Current policies* scenario

| | Black coal | Black coal with CCS | Brown coal | Gas combined cycle | Gas open cycle (small) | Gas open cycle (large) | Gas with CCS | Gas reciprocating | Hydrogen reciprocating | Biomass (small scale) | Biomass with CCS (large scale) | Large scale solar PV | Rooftop solar panels | Solar thermal (12 hrs) | Wind | Offshore wind | Wave | Nuclear (SMR) | Tidal/ocean current | Fuel cell | Integrated solar and battery (2 hrs) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW |
| **2021** | 4343 | 9077 | 6704 | 1559 | 1290 | 765 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2022** | 4343 | 9077 | 6704 | 1559 | 1290 | 762 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2023** | 4328 | 9053 | 6680 | 1554 | 1285 | 760 | 4004 | 1629 | 1982 | 6954 | 17918 | 1386 | 1283 | 6581 | 1951 | 4616 | 9745 | - | 7092 | 7613 | 1943 |
| **2024** | 4313 | 9028 | 6657 | 1548 | 1281 | 757 | 3997 | 1624 | 1975 | 6954 | 17863 | 1335 | 1238 | 6476 | 1941 | 4599 | 9745 | - | 7092 | 7223 | 1878 |
| **2025** | 4298 | 9004 | 6634 | 1543 | 1277 | 754 | 3991 | 1618 | 1968 | 6954 | 17808 | 1287 | 1195 | 6333 | 1927 | 4599 | 9745 | - | 7092 | 6871 | 1812 |
| **2026** | 4283 | 8980 | 6610 | 1537 | 1272 | 752 | 3984 | 1612 | 1961 | 6954 | 17753 | 1248 | 1160 | 6191 | 1915 | 4599 | 9745 | - | 7092 | 6435 | 1760 |
| **2027** | 4268 | 8956 | 6587 | 1532 | 1268 | 749 | 3977 | 1607 | 1954 | 6954 | 17698 | 1210 | 1121 | 6035 | 1906 | 4599 | 9745 | - | 7092 | 5939 | 1709 |
| **2028** | 4253 | 8932 | 6564 | 1527 | 1263 | 746 | 3971 | 1601 | 1948 | 6954 | 17644 | 1139 | 1062 | 5894 | 1903 | 4599 | 9745 | - | 7092 | 5415 | 1638 |
| **2029** | 4238 | 8908 | 6541 | 1521 | 1259 | 744 | 3964 | 1595 | 1941 | 6954 | 17589 | 1073 | 1003 | 5771 | 1900 | 4584 | 9745 | - | 7092 | 5029 | 1568 |
| **2030** | 4223 | 8884 | 6518 | 1516 | 1254 | 741 | 3957 | 1590 | 1934 | 6954 | 17535 | 1013 | 949 | 5660 | 1897 | 4545 | 9745 | 16773 | 7092 | 4294 | 1505 |
| **2031** | 4208 | 8860 | 6495 | 1511 | 1250 | 739 | 3951 | 1584 | 1927 | 6954 | 17481 | 980 | 918 | 5559 | 1894 | 4506 | 9745 | 16773 | 7092 | 3676 | 1465 |
| **2032** | 4194 | 8837 | 6473 | 1505 | 1246 | 736 | 3944 | 1579 | 1920 | 6954 | 17427 | 934 | 877 | 5467 | 1892 | 4482 | 9745 | 16773 | 7092 | 3131 | 1413 |
| **2033** | 4179 | 8813 | 6450 | 1500 | 1241 | 733 | 3938 | 1573 | 1914 | 6954 | 17374 | 883 | 831 | 5382 | 1889 | 4482 | 9745 | 16773 | 7092 | 3094 | 1355 |
| **2034** | 4164 | 8790 | 6427 | 1495 | 1237 | 731 | 3931 | 1568 | 1907 | 6954 | 17320 | 842 | 793 | 5303 | 1886 | 4482 | 9745 | 16773 | 7008 | 3061 | 1304 |
| **2035** | 4150 | 8766 | 6405 | 1490 | 1233 | 728 | 3924 | 1562 | 1900 | 6954 | 17267 | 825 | 776 | 5229 | 1884 | 4482 | 9745 | 16773 | 6844 | 3023 | 1273 |
| **2036** | 4135 | 8743 | 6383 | 1484 | 1228 | 726 | 3918 | 1557 | 1894 | 6954 | 17214 | 807 | 759 | 5159 | 1883 | 4482 | 9745 | 16773 | 6680 | 2991 | 1241 |
| **2037** | 4121 | 8720 | 6360 | 1479 | 1224 | 723 | 3911 | 1551 | 1887 | 6954 | 17161 | 789 | 742 | 5093 | 1882 | 4482 | 9745 | 16773 | 6600 | 2958 | 1209 |
| **2038** | 4106 | 8696 | 6338 | 1474 | 1220 | 721 | 3905 | 1546 | 1881 | 6954 | 17108 | 763 | 718 | 5029 | 1879 | 4482 | 9745 | 16773 | 6597 | 2934 | 1170 |
| **2039** | 4092 | 8673 | 6316 | 1469 | 1215 | 718 | 3899 | 1540 | 1874 | 6954 | 17056 | 749 | 705 | 4969 | 1874 | 4482 | 9745 | 16773 | 6594 | 2912 | 1142 |
| **2040** | 4078 | 8650 | 6294 | 1464 | 1211 | 716 | 3892 | 1535 | 1867 | 6954 | 17004 | 733 | 691 | 4894 | 1868 | 4482 | 9745 | 16773 | 6590 | 2899 | 1114 |
| **2041** | 4063 | 8576 | 6272 | 1459 | 1207 | 713 | 3835 | 1530 | 1861 | 6954 | 16900 | 726 | 683 | 4806 | 1863 | 4481 | 9745 | 16773 | 6590 | 2890 | 1095 |
| **2042** | 4049 | 8453 | 6250 | 1453 | 1203 | 711 | 3730 | 1524 | 1854 | 6954 | 16747 | 717 | 674 | 4706 | 1859 | 4471 | 9745 | 16773 | 6590 | 2886 | 1077 |
| **2043** | 4035 | 8297 | 6228 | 1448 | 1198 | 708 | 3593 | 1519 | 1848 | 6954 | 16561 | 706 | 664 | 4613 | 1854 | 4461 | 9745 | 16773 | 6582 | 2884 | 1061 |
| **2044** | 4021 | 8168 | 6206 | 1443 | 1194 | 706 | 3482 | 1514 | 1841 | 6954 | 16403 | 695 | 654 | 4525 | 1850 | 4452 | 9745 | 16773 | 6571 | 2884 | 1046 |
| **2045** | 4007 | 8069 | 6184 | 1438 | 1190 | 703 | 3400 | 1508 | 1835 | 6954 | 16275 | 686 | 646 | 4442 | 1846 | 4452 | 9745 | 16773 | 6561 | 2884 | 1031 |
| **2046** | 3993 | 7989 | 6163 | 1433 | 1186 | 701 | 3338 | 1503 | 1828 | 6954 | 16166 | 680 | 640 | 4364 | 1843 | 4449 | 9745 | 16773 | 6555 | 2884 | 1018 |
| **2047** | 3979 | 7981 | 6141 | 1428 | 1182 | 698 | 3334 | 1498 | 1822 | 6954 | 16074 | 671 | 631 | 4290 | 1839 | 4447 | 9745 | 16773 | 6551 | 2883 | 1005 |
| **2048** | 3965 | 7974 | 6120 | 1423 | 1178 | 696 | 3331 | 1493 | 1816 | 6954 | 15996 | 660 | 622 | 4219 | 1836 | 4441 | 9745 | 16773 | 6548 | 2883 | 992 |
| **2049** | 3951 | 7966 | 6098 | 1418 | 1173 | 693 | 3328 | 1487 | 1809 | 6954 | 15929 | 650 | 612 | 4152 | 1832 | 4438 | 9745 | 16773 | 6548 | 2883 | 979 |
| **2050** | 3937 | 7958 | 6077 | 1413 | 1169 | 691 | 3324 | 1482 | 1803 | 6954 | 15869 | 644 | 606 | 4103 | 1828 | 4431 | 9745 | 16773 | 6493 | 2882 | 970 |

## Apx Table B.2 Current and projected generation technology capital costs under the *Global NZE by 2050* scenario

| | Black coal | Black coal with CCS | Brown coal | Gas combined cycle | Gas open cycle (small) | Gas open cycle (large) | Gas with CCS | Gas reciprocating | Hydrogen reciprocating | Biomass (small scale) | Biomass with CCS (large scale) | Large scale solar PV | Rooftop solar panels | Solar thermal (12 hrs) | Wind | Offshore wind | Wave | Nuclear (SMR) | Tidal/ocean current | Fuel cell | Integrated solar and battery (2 hrs) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW |
| **2021** | 4343 | 9077 | 6704 | 1559 | 1290 | 765 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2022** | 4343 | 9077 | 6704 | 1559 | 1290 | 762 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2023** | 4313 | 9028 | 6657 | 1548 | 1281 | 760 | 3997 | 1624 | 1975 | 6954 | 17863 | 1301 | 1208 | 6112 | 1848 | 3904 | 8046 | - | 7092 | 6922 | 1809 |
| **2024** | 4298 | 9004 | 6634 | 1543 | 1277 | 757 | 3991 | 1618 | 1968 | 6954 | 17808 | 1246 | 1159 | 5860 | 1803 | 3688 | 6642 | - | 7092 | 6437 | 1703 |
| **2025** | 4283 | 8980 | 6610 | 1537 | 1272 | 754 | 3984 | 1612 | 1961 | 6952 | 17753 | 1184 | 1105 | 5592 | 1762 | 3477 | 5484 | - | 7092 | 6037 | 1604 |
| **2026** | 4268 | 8956 | 6587 | 1532 | 1268 | 752 | 3977 | 1607 | 1954 | 6951 | 17698 | 1095 | 1027 | 5368 | 1727 | 3289 | 4527 | - | 7092 | 5717 | 1493 |
| **2027** | 4253 | 8932 | 6564 | 1527 | 1263 | 749 | 3971 | 1601 | 1948 | 6949 | 17644 | 995 | 939 | 5201 | 1695 | 3161 | 3738 | - | 7092 | 5481 | 1375 |
| **2028** | 4238 | 8908 | 6541 | 1521 | 1259 | 746 | 3964 | 1595 | 1941 | 6949 | 17589 | 905 | 859 | 5035 | 1669 | 3082 | 3086 | - | 7092 | 5321 | 1270 |
| **2029** | 4223 | 8884 | 6518 | 1516 | 1254 | 744 | 3957 | 1590 | 1934 | 6949 | 17535 | 841 | 802 | 4846 | 1649 | 3021 | 2547 | - | 7092 | 5187 | 1187 |
| **2030** | 4208 | 8631 | 6495 | 1511 | 1250 | 741 | 3725 | 1584 | 1927 | 6949 | 17251 | 785 | 752 | 4657 | 1633 | 2967 | 2103 | 7904 | 7092 | 5103 | 1114 |
| **2031** | 4194 | 8333 | 6473 | 1505 | 1246 | 739 | 3448 | 1579 | 1920 | 6949 | 16921 | 742 | 712 | 4493 | 1621 | 2919 | 2103 | 7904 | 7092 | 5050 | 1054 |
| **2032** | 4179 | 8029 | 6450 | 1500 | 1241 | 736 | 3165 | 1573 | 1914 | 6949 | 16585 | 708 | 681 | 4372 | 1612 | 2876 | 2103 | 7904 | 7092 | 5048 | 1007 |
| **2033** | 4164 | 7952 | 6427 | 1495 | 1237 | 733 | 3106 | 1568 | 1907 | 6949 | 16478 | 685 | 659 | 4258 | 1605 | 2838 | 2103 | 7871 | 7092 | 5046 | 975 |
| **2034** | 4150 | 7919 | 6405 | 1490 | 1233 | 731 | 3090 | 1562 | 1900 | 6907 | 16415 | 664 | 639 | 4162 | 1597 | 2803 | 2103 | 7839 | 7092 | 5044 | 948 |
| **2035** | 4135 | 7890 | 6383 | 1484 | 1228 | 728 | 3078 | 1557 | 1894 | 6818 | 16357 | 644 | 620 | 4063 | 1586 | 2772 | 2103 | 7806 | 7092 | 5043 | 926 |
| **2036** | 4121 | 7864 | 6360 | 1479 | 1224 | 726 | 3069 | 1551 | 1887 | 6728 | 16300 | 625 | 602 | 3980 | 1576 | 2744 | 2103 | 7806 | 7088 | 5042 | 905 |
| **2037** | 4106 | 7839 | 6338 | 1474 | 1220 | 723 | 3060 | 1546 | 1881 | 6682 | 16246 | 610 | 587 | 3895 | 1568 | 2718 | 2103 | 7806 | 7083 | 5041 | 887 |
| **2038** | 4092 | 7815 | 6316 | 1469 | 1215 | 721 | 3053 | 1540 | 1874 | 6682 | 16193 | 597 | 576 | 3816 | 1563 | 2694 | 2103 | 7806 | 7079 | 5041 | 873 |
| **2039** | 4078 | 7792 | 6294 | 1464 | 1211 | 718 | 3046 | 1535 | 1867 | 6682 | 16140 | 587 | 566 | 3718 | 1558 | 2673 | 2103 | 7806 | 7078 | 5040 | 860 |
| **2040** | 4063 | 7768 | 6272 | 1459 | 1207 | 716 | 3039 | 1530 | 1861 | 6682 | 16087 | 578 | 557 | 3620 | 1553 | 2653 | 2103 | 7806 | 7078 | 5040 | 849 |
| **2041** | 4049 | 7745 | 6250 | 1453 | 1203 | 713 | 3033 | 1524 | 1854 | 6682 | 16035 | 571 | 550 | 3511 | 1549 | 2635 | 2103 | 7806 | 7078 | 5039 | 840 |
| **2042** | 4035 | 7722 | 6228 | 1448 | 1198 | 711 | 3026 | 1519 | 1848 | 6682 | 15983 | 565 | 544 | 3418 | 1546 | 2618 | 2103 | 7806 | 7008 | 5039 | 832 |
| **2043** | 4021 | 7699 | 6206 | 1443 | 1194 | 708 | 3020 | 1514 | 1841 | 6682 | 15931 | 558 | 537 | 3321 | 1542 | 2602 | 2103 | 7806 | 6937 | 5039 | 823 |
| **2044** | 4007 | 7676 | 6184 | 1438 | 1190 | 706 | 3013 | 1508 | 1835 | 6682 | 15880 | 553 | 532 | 3244 | 1539 | 2588 | 2103 | 7806 | 6866 | 5039 | 816 |
| **2045** | 3993 | 7654 | 6163 | 1433 | 1186 | 703 | 3007 | 1503 | 1828 | 6682 | 15828 | 547 | 526 | 3171 | 1536 | 2574 | 2103 | 7806 | 6863 | 5039 | 809 |
| **2046** | 3979 | 7631 | 6141 | 1428 | 1182 | 701 | 3000 | 1498 | 1822 | 6682 | 15777 | 541 | 520 | 3113 | 1533 | 2562 | 2103 | 7806 | 6862 | 5038 | 801 |
| **2047** | 3965 | 7608 | 6120 | 1423 | 1178 | 698 | 2994 | 1493 | 1816 | 6682 | 15726 | 535 | 514 | 3056 | 1530 | 2550 | 1637 | 7806 | 6860 | 5038 | 793 |
| **2048** | 3951 | 7586 | 6098 | 1418 | 1173 | 696 | 2987 | 1487 | 1809 | 6653 | 15675 | 529 | 509 | 3004 | 1527 | 2535 | 1625 | 7806 | 6860 | 5038 | 786 |
| **2049** | 3937 | 7564 | 6077 | 1413 | 1169 | 693 | 2981 | 1482 | 1803 | 6572 | 15624 | 523 | 503 | 2953 | 1523 | 2517 | 1622 | 7806 | 6835 | 5038 | 779 |
| **2050** | 3930 | 7552 | 6066 | 1411 | 1167 | 691 | 2978 | 1480 | 1800 | 6517 | 15599 | 521 | 500 | 2911 | 1521 | 2506 | 1621 | 7806 | 6822 | 5038 | 776 |

## Apx Table B.3 Current and projected generation technology capital costs under the *Global NZE post 2050* scenario

| | Black coal | Black coal with CCS | Brown coal | Gas combined cycle | Gas open cycle (small) | Gas open cycle (large) | Gas with CCS | Gas reciprocating | Hydrogen reciprocating | Biomass (small scale) | Biomass with CCS (large scale) | Large scale solar PV | Rooftop solar panels | Solar thermal (12 hrs) | Wind | Offshore wind | Wave | Nuclear (SMR) | Tidal/ocean current | Fuel cell | Integrated solar and battery (2 hrs) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW | $/kW |
| **2021** | 4343 | 9077 | 6704 | 1559 | 1290 | 765 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2022** | 4343 | 9077 | 6704 | 1559 | 1290 | 762 | 4011 | 1635 | 1989 | 6954 | 17974 | 1441 | 1333 | 6693 | 1960 | 4649 | 9745 | - | 7092 | 8032 | 2004 |
| **2023** | 4328 | 9053 | 6680 | 1554 | 1285 | 760 | 4004 | 1629 | 1982 | 6954 | 17918 | 1366 | 1266 | 6530 | 1948 | 4614 | 9547 | - | 7092 | 7404 | 1926 |
| **2024** | 4313 | 8947 | 6657 | 1548 | 1281 | 757 | 3998 | 1624 | 1975 | 6954 | 17781 | 1305 | 1212 | 6309 | 1933 | 4596 | 9547 | - | 7092 | 6844 | 1849 |
| **2025** | 4298 | 8925 | 6634 | 1543 | 1277 | 754 | 3992 | 1618 | 1968 | 6954 | 17604 | 1250 | 1163 | 6043 | 1916 | 4596 | 9547 | - | 7092 | 6372 | 1768 |
| **2026** | 4283 | 8902 | 6610 | 1537 | 1272 | 752 | 3986 | 1612 | 1961 | 6954 | 17396 | 1207 | 1124 | 5798 | 1889 | 4593 | 9547 | - | 7092 | 5924 | 1699 |
| **2027** | 4268 | 8880 | 6587 | 1532 | 1268 | 749 | 3980 | 1607 | 1954 | 6954 | 17252 | 1161 | 1083 | 5612 | 1860 | 4577 | 9547 | - | 7092 | 5398 | 1630 |
| **2028** | 4253 | 8858 | 6564 | 1527 | 1263 | 746 | 3940 | 1601 | 1948 | 6954 | 17132 | 1121 | 1046 | 5481 | 1829 | 4542 | 9547 | - | 7092 | 4847 | 1566 |
| **2029** | 4238 | 8836 | 6541 | 1521 | 1259 | 744 | 3901 | 1595 | 1941 | 6954 | 17033 | 1080 | 1008 | 5372 | 1803 | 4492 | 9547 | - | 7092 | 4388 | 1503 |
| **2030** | 4223 | 8747 | 6518 | 1516 | 1254 | 741 | 3784 | 1590 | 1934 | 6954 | 16946 | 1046 | 977 | 5236 | 1778 | 4437 | 9547 | 7859 | 7092 | 4000 | 1447 |
| **2031** | 4208 | 8572 | 6495 | 1511 | 1250 | 739 | 3670 | 1584 | 1927 | 6952 | 16874 | 1011 | 945 | 5075 | 1759 | 4386 | 9547 | 7832 | 7092 | 3760 | 1392 |
| **2032** | 4194 | 8401 | 6473 | 1505 | 1246 | 736 | 3560 | 1579 | 1920 | 6950 | 16811 | 981 | 917 | 4902 | 1749 | 4351 | 9547 | 7825 | 7092 | 3604 | 1346 |
| **2033** | 4179 | 8233 | 6450 | 1500 | 1241 | 733 | 3454 | 1573 | 1914 | 6948 | 16754 | 928 | 869 | 4750 | 1735 | 4335 | 9547 | 7825 | 7092 | 3597 | 1286 |
| **2034** | 4164 | 8173 | 6427 | 1495 | 1237 | 731 | 3323 | 1568 | 1907 | 6948 | 16700 | 885 | 829 | 4623 | 1719 | 4332 | 9547 | 7825 | 7092 | 3592 | 1237 |
| **2035** | 4150 | 8149 | 6405 | 1490 | 1233 | 728 | 3316 | 1562 | 1900 | 6948 | 16646 | 846 | 794 | 4519 | 1701 | 4332 | 9547 | 7825 | 6968 | 3587 | 1194 |
| **2036** | 4135 | 8123 | 6383 | 1484 | 1228 | 726 | 3307 | 1557 | 1894 | 6947 | 16590 | 811 | 762 | 4440 | 1688 | 4239 | 9547 | 7824 | 6843 | 3582 | 1153 |
| **2037** | 4121 | 8097 | 6360 | 1479 | 1224 | 723 | 3299 | 1551 | 1887 | 6947 | 16535 | 783 | 736 | 4367 | 1677 | 4100 | 9547 | 7823 | 6717 | 3578 | 1119 |
| **2038** | 4106 | 8072 | 6338 | 1474 | 1220 | 721 | 3290 | 1546 | 1881 | 6947 | 16480 | 741 | 699 | 4303 | 1666 | 3932 | 9547 | 7822 | 6715 | 3574 | 1073 |
| **2039** | 4092 | 8049 | 6316 | 1469 | 1215 | 718 | 3283 | 1540 | 1874 | 6947 | 16427 | 722 | 681 | 4236 | 1659 | 3838 | 8678 | 7822 | 6712 | 3570 | 1048 |
| **2040** | 4078 | 8025 | 6294 | 1464 | 1211 | 716 | 3276 | 1535 | 1867 | 6947 | 16375 | 689 | 653 | 4181 | 1648 | 3772 | 7889 | 7822 | 6712 | 3567 | 1012 |
| **2041** | 4063 | 8002 | 6272 | 1459 | 1207 | 713 | 3269 | 1530 | 1861 | 6947 | 16322 | 668 | 634 | 4117 | 1638 | 3698 | 7171 | 7822 | 6712 | 3564 | 987 |
| **2042** | 4049 | 7978 | 6250 | 1453 | 1203 | 711 | 3262 | 1524 | 1854 | 6947 | 16269 | 645 | 612 | 4051 | 1625 | 3616 | 6518 | 7822 | 6712 | 3563 | 960 |
| **2043** | 4035 | 7954 | 6228 | 1448 | 1198 | 708 | 3255 | 1519 | 1848 | 6946 | 16216 | 629 | 598 | 3982 | 1615 | 3530 | 5925 | 7822 | 6706 | 3562 | 943 |
| **2044** | 4021 | 7930 | 6206 | 1443 | 1194 | 706 | 3247 | 1514 | 1841 | 6946 | 16164 | 612 | 583 | 3918 | 1603 | 3461 | 5386 | 7822 | 6698 | 3562 | 924 |
| **2045** | 4007 | 7906 | 6184 | 1438 | 1190 | 703 | 3240 | 1508 | 1835 | 6915 | 16111 | 596 | 568 | 3861 | 1590 | 3406 | 4896 | 7822 | 6690 | 3561 | 907 |
| **2046** | 3993 | 7883 | 6163 | 1433 | 1186 | 701 | 3233 | 1503 | 1828 | 6884 | 16059 | 580 | 554 | 3794 | 1577 | 3358 | 4451 | 7822 | 6685 | 3561 | 889 |
| **2047** | 3979 | 7860 | 6141 | 1428 | 1182 | 698 | 3226 | 1498 | 1822 | 6853 | 16007 | 566 | 542 | 3718 | 1567 | 3308 | 4046 | 7822 | 6682 | 3560 | 874 |
| **2048** | 3965 | 7837 | 6120 | 1423 | 1178 | 696 | 3219 | 1493 | 1816 | 6853 | 15956 | 553 | 529 | 3627 | 1559 | 3256 | 3678 | 7822 | 6679 | 3560 | 859 |
| **2049** | 3951 | 7815 | 6098 | 1418 | 1173 | 693 | 3213 | 1487 | 1809 | 6840 | 15905 | 541 | 518 | 3540 | 1552 | 3206 | 3343 | 7822 | 6679 | 3559 | 846 |
| **2050** | 3937 | 7792 | 6077 | 1413 | 1169 | 691 | 3206 | 1482 | 1803 | 6765 | 15854 | 530 | 508 | 3478 | 1546 | 3168 | 3039 | 7822 | 6634 | 3558 | 834 |

Apx Table B.4 One and two hour battery cost data by storage duration, component and total costs

| | Battery storage (1 hr) | | | | | | | | | Battery storage (2 hrs) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total | | | Battery | | | BOP | | | Total | | | Battery | | | BOP | | |
| | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 |
| | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh |
| **2021** | 790 | 790 | 790 | 326 | 326 | 326 | 464 | 464 | 464 | 527 | 527 | 527 | 287 | 287 | 287 | 240 | 240 | 240 |
| **2022** | 790 | 790 | 790 | 326 | 326 | 326 | 464 | 464 | 464 | 527 | 527 | 527 | 287 | 287 | 287 | 240 | 240 | 240 |
| **2023** | 767 | 764 | 741 | 309 | 308 | 286 | 458 | 456 | 455 | 509 | 507 | 487 | 272 | 271 | 252 | 237 | 235 | 235 |
| **2024** | 749 | 739 | 698 | 297 | 292 | 252 | 453 | 447 | 446 | 495 | 488 | 453 | 261 | 257 | 222 | 234 | 231 | 230 |
| **2025** | 738 | 715 | 670 | 290 | 276 | 233 | 448 | 439 | 437 | 487 | 470 | 431 | 255 | 243 | 205 | 231 | 227 | 226 |
| **2026** | 727 | 692 | 643 | 285 | 261 | 215 | 442 | 431 | 428 | 479 | 453 | 410 | 251 | 230 | 189 | 228 | 223 | 221 |
| **2027** | 716 | 670 | 618 | 279 | 247 | 199 | 437 | 423 | 420 | 471 | 436 | 392 | 245 | 217 | 175 | 226 | 219 | 217 |
| **2028** | 705 | 649 | 596 | 274 | 233 | 185 | 431 | 415 | 411 | 464 | 420 | 375 | 241 | 205 | 163 | 223 | 215 | 212 |
| **2029** | 696 | 628 | 576 | 270 | 221 | 174 | 426 | 407 | 402 | 458 | 405 | 361 | 237 | 194 | 153 | 220 | 210 | 208 |
| **2030** | 687 | 608 | 553 | 266 | 209 | 159 | 421 | 399 | 393 | 452 | 390 | 344 | 234 | 184 | 140 | 217 | 206 | 203 |
| **2031** | 676 | 589 | 534 | 260 | 197 | 149 | 415 | 391 | 385 | 444 | 376 | 330 | 229 | 174 | 132 | 215 | 202 | 199 |
| **2032** | 664 | 576 | 517 | 254 | 193 | 142 | 410 | 383 | 376 | 436 | 368 | 319 | 224 | 170 | 125 | 212 | 198 | 194 |
| **2033** | 653 | 565 | 502 | 249 | 190 | 135 | 405 | 375 | 367 | 428 | 361 | 309 | 219 | 167 | 119 | 209 | 194 | 190 |
| **2034** | 640 | 553 | 493 | 241 | 186 | 134 | 399 | 367 | 358 | 418 | 353 | 303 | 212 | 163 | 118 | 206 | 190 | 185 |
| **2035** | 628 | 541 | 483 | 234 | 182 | 134 | 394 | 359 | 349 | 410 | 346 | 298 | 206 | 160 | 118 | 204 | 185 | 181 |
| **2036** | 614 | 529 | 474 | 226 | 178 | 133 | 389 | 351 | 341 | 399 | 338 | 293 | 199 | 156 | 117 | 201 | 181 | 176 |
| **2037** | 602 | 517 | 464 | 218 | 174 | 132 | 383 | 343 | 332 | 390 | 330 | 288 | 192 | 153 | 116 | 198 | 177 | 171 |
| **2038** | 588 | 505 | 455 | 210 | 170 | 131 | 378 | 335 | 323 | 380 | 323 | 283 | 185 | 150 | 116 | 195 | 173 | 167 |
| **2039** | 576 | 494 | 445 | 204 | 167 | 131 | 373 | 327 | 314 | 372 | 316 | 278 | 180 | 147 | 115 | 192 | 169 | 162 |
| **2040** | 565 | 483 | 436 | 197 | 164 | 130 | 367 | 319 | 306 | 363 | 309 | 272 | 174 | 145 | 115 | 190 | 165 | 158 |
| **2041** | 555 | 473 | 426 | 193 | 162 | 130 | 362 | 311 | 297 | 357 | 303 | 267 | 170 | 143 | 114 | 187 | 160 | 153 |
| **2042** | 548 | 464 | 418 | 191 | 162 | 129 | 356 | 302 | 288 | 353 | 299 | 263 | 169 | 142 | 114 | 184 | 156 | 149 |
| **2043** | 541 | 456 | 409 | 190 | 161 | 129 | 351 | 294 | 279 | 349 | 294 | 258 | 167 | 142 | 114 | 181 | 152 | 144 |
| **2044** | 531 | 446 | 399 | 186 | 160 | 129 | 346 | 286 | 271 | 342 | 288 | 253 | 164 | 140 | 114 | 179 | 148 | 140 |
| **2045** | 523 | 437 | 390 | 183 | 158 | 129 | 340 | 278 | 262 | 337 | 283 | 248 | 161 | 139 | 113 | 176 | 144 | 135 |
| **2046** | 516 | 428 | 381 | 181 | 157 | 128 | 335 | 270 | 253 | 332 | 278 | 244 | 159 | 139 | 113 | 173 | 140 | 131 |
| **2047** | 509 | 419 | 372 | 180 | 157 | 128 | 330 | 262 | 244 | 328 | 273 | 239 | 158 | 138 | 113 | 170 | 135 | 126 |
| **2048** | 503 | 410 | 363 | 178 | 156 | 128 | 324 | 254 | 235 | 325 | 269 | 234 | 157 | 137 | 113 | 168 | 131 | 122 |
| **2049** | 497 | 402 | 354 | 178 | 156 | 128 | 319 | 246 | 227 | 321 | 264 | 230 | 156 | 137 | 113 | 165 | 127 | 117 |
| **2050** | 485 | 385 | 337 | 177 | 155 | 128 | 308 | 230 | 209 | 315 | 255 | 220 | 156 | 137 | 112 | 159 | 119 | 108 |

Note: To convert battery costs to $/kW, multiply by the storage duration.

Apx Table B.5 Four and eight hour battery cost data by storage duration, component and total costs

| | Battery storage (4 hrs) | | | | | | | | | Battery storage (8 hrs) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total | | | Battery | | | BOP | | | Total | | | Battery | | | BOP | | |
| | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 | Current policies | Global NZE post 2050 | Global NZE by 2050 |
| | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh | $/kWh |
| **2021** | 407 | 407 | 407 | 287 | 287 | 287 | 120 | 120 | 120 | 357 | 357 | 357 | 287 | 287 | 287 | 70 | 70 | 70 |
| **2022** | 407 | 407 | 407 | 287 | 287 | 287 | 120 | 120 | 120 | 357 | 357 | 357 | 287 | 287 | 287 | 70 | 70 | 70 |
| **2023** | 391 | 390 | 369 | 272 | 271 | 252 | 119 | 118 | 118 | 341 | 341 | 321 | 272 | 271 | 252 | 70 | 69 | 69 |
| **2024** | 379 | 373 | 338 | 261 | 257 | 222 | 117 | 116 | 116 | 330 | 325 | 290 | 261 | 257 | 222 | 69 | 68 | 68 |
| **2025** | 371 | 357 | 318 | 255 | 243 | 205 | 116 | 114 | 113 | 323 | 310 | 271 | 255 | 243 | 205 | 68 | 67 | 66 |
| **2026** | 365 | 341 | 300 | 251 | 230 | 189 | 115 | 112 | 111 | 318 | 295 | 254 | 251 | 230 | 189 | 67 | 66 | 65 |
| **2027** | 359 | 327 | 284 | 245 | 217 | 175 | 113 | 110 | 109 | 312 | 281 | 239 | 245 | 217 | 175 | 66 | 64 | 64 |
| **2028** | 353 | 313 | 270 | 241 | 205 | 163 | 112 | 108 | 107 | 306 | 268 | 225 | 241 | 205 | 163 | 66 | 63 | 62 |
| **2029** | 348 | 300 | 257 | 237 | 194 | 153 | 110 | 106 | 104 | 302 | 256 | 214 | 237 | 194 | 153 | 65 | 62 | 61 |
| **2030** | 343 | 287 | 242 | 234 | 184 | 140 | 109 | 103 | 102 | 298 | 244 | 200 | 234 | 184 | 140 | 64 | 61 | 60 |
| **2031** | 337 | 275 | 231 | 229 | 174 | 132 | 108 | 101 | 100 | 292 | 233 | 190 | 229 | 174 | 132 | 63 | 59 | 58 |
| **2032** | 330 | 269 | 222 | 224 | 170 | 125 | 106 | 99 | 97 | 286 | 228 | 182 | 224 | 170 | 125 | 62 | 58 | 57 |
| **2033** | 324 | 264 | 214 | 219 | 167 | 119 | 105 | 97 | 95 | 280 | 224 | 175 | 219 | 167 | 119 | 61 | 57 | 56 |
| **2034** | 315 | 259 | 211 | 212 | 163 | 118 | 104 | 95 | 93 | 272 | 219 | 173 | 212 | 163 | 118 | 61 | 56 | 54 |
| **2035** | 308 | 253 | 208 | 206 | 160 | 118 | 102 | 93 | 91 | 266 | 215 | 171 | 206 | 160 | 118 | 60 | 54 | 53 |
| **2036** | 299 | 247 | 205 | 199 | 156 | 117 | 101 | 91 | 88 | 258 | 210 | 169 | 199 | 156 | 117 | 59 | 53 | 52 |
| **2037** | 292 | 242 | 202 | 192 | 153 | 116 | 99 | 89 | 86 | 251 | 205 | 167 | 192 | 153 | 116 | 58 | 52 | 50 |
| **2038** | 283 | 237 | 199 | 185 | 150 | 116 | 98 | 87 | 84 | 242 | 201 | 165 | 185 | 150 | 116 | 57 | 51 | 49 |
| **2039** | 276 | 232 | 197 | 180 | 147 | 115 | 97 | 85 | 82 | 236 | 197 | 163 | 180 | 147 | 115 | 57 | 50 | 48 |
| **2040** | 269 | 227 | 194 | 174 | 145 | 115 | 95 | 83 | 79 | 230 | 193 | 161 | 174 | 145 | 115 | 56 | 48 | 46 |
| **2041** | 264 | 223 | 191 | 170 | 143 | 114 | 94 | 81 | 77 | 225 | 190 | 159 | 170 | 143 | 114 | 55 | 47 | 45 |
| **2042** | 261 | 221 | 189 | 169 | 142 | 114 | 92 | 78 | 75 | 223 | 188 | 158 | 169 | 142 | 114 | 54 | 46 | 44 |
| **2043** | 258 | 218 | 186 | 167 | 142 | 114 | 91 | 76 | 72 | 221 | 187 | 156 | 167 | 142 | 114 | 53 | 45 | 42 |
| **2044** | 253 | 215 | 184 | 164 | 140 | 114 | 90 | 74 | 70 | 216 | 184 | 155 | 164 | 140 | 114 | 52 | 43 | 41 |
| **2045** | 249 | 212 | 181 | 161 | 139 | 113 | 88 | 72 | 68 | 213 | 182 | 153 | 161 | 139 | 113 | 52 | 42 | 40 |
| **2046** | 246 | 209 | 179 | 159 | 139 | 113 | 87 | 70 | 66 | 210 | 180 | 151 | 159 | 139 | 113 | 51 | 41 | 38 |
| **2047** | 244 | 206 | 176 | 158 | 138 | 113 | 85 | 68 | 63 | 208 | 178 | 150 | 158 | 138 | 113 | 50 | 40 | 37 |
| **2048** | 241 | 203 | 174 | 157 | 137 | 113 | 84 | 66 | 61 | 206 | 176 | 148 | 157 | 137 | 113 | 49 | 39 | 36 |
| **2049** | 239 | 201 | 171 | 156 | 137 | 113 | 83 | 64 | 59 | 205 | 174 | 147 | 156 | 137 | 113 | 48 | 37 | 34 |
| **2050** | 236 | 196 | 167 | 156 | 137 | 112 | 80 | 60 | 54 | 203 | 172 | 144 | 156 | 137 | 112 | 47 | 35 | 32 |

Note: To convert battery costs to $/kW, multiply by the storage duration.

Apx Table B.6 Pumped hydro storage cost data by duration, all scenarios, total cost basis

| | $/kW | | | | | | | $/kWh | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 6hrs | 8hrs | 12hrs | 24hrs | 24hrs Tas | 48hrs | 48hrs Tas | 6hrs | 8hrs | 12hrs | 24hrs | 24hrs Tas | 48hrs | 48hrs Tas |
| **2021** | 2323 | 2520 | 2711 | 3537 | 2185 | 5313 | 2468 | 387 | 315 | 226 | 147 | 91 | 111 | 51 |
| **2022** | 2319 | 2516 | 2706 | 3531 | 2181 | 5304 | 2464 | 387 | 315 | 226 | 147 | 91 | 111 | 51 |
| **2023** | 2315 | 2512 | 2701 | 3525 | 2178 | 5295 | 2460 | 386 | 314 | 225 | 147 | 91 | 110 | 51 |
| **2024** | 2312 | 2507 | 2697 | 3519 | 2174 | 5286 | 2455 | 385 | 313 | 225 | 147 | 91 | 110 | 51 |
| **2025** | 2308 | 2503 | 2692 | 3513 | 2170 | 5277 | 2451 | 385 | 313 | 224 | 146 | 90 | 110 | 51 |
| **2026** | 2304 | 2499 | 2688 | 3507 | 2166 | 5268 | 2447 | 384 | 312 | 224 | 146 | 90 | 110 | 51 |
| **2027** | 2300 | 2495 | 2683 | 3501 | 2163 | 5259 | 2443 | 383 | 312 | 224 | 146 | 90 | 110 | 51 |
| **2028** | 2296 | 2490 | 2678 | 3495 | 2159 | 5250 | 2439 | 383 | 311 | 223 | 146 | 90 | 109 | 51 |
| **2029** | 2292 | 2486 | 2674 | 3489 | 2155 | 5241 | 2434 | 382 | 311 | 223 | 145 | 90 | 109 | 51 |
| **2030** | 2288 | 2482 | 2669 | 3483 | 2152 | 5232 | 2430 | 381 | 310 | 222 | 145 | 90 | 109 | 51 |
| **2031** | 2284 | 2478 | 2665 | 3477 | 2148 | 5223 | 2426 | 381 | 310 | 222 | 145 | 89 | 109 | 51 |
| **2032** | 2280 | 2473 | 2660 | 3471 | 2144 | 5214 | 2422 | 380 | 309 | 222 | 145 | 89 | 109 | 50 |
| **2033** | 2276 | 2469 | 2656 | 3465 | 2141 | 5205 | 2418 | 379 | 309 | 221 | 144 | 89 | 108 | 50 |
| **2034** | 2272 | 2465 | 2651 | 3459 | 2137 | 5196 | 2414 | 379 | 308 | 221 | 144 | 89 | 108 | 50 |
| **2035** | 2268 | 2461 | 2647 | 3453 | 2133 | 5188 | 2410 | 378 | 308 | 221 | 144 | 89 | 108 | 50 |
| **2036** | 2265 | 2457 | 2642 | 3447 | 2130 | 5179 | 2406 | 377 | 307 | 220 | 144 | 89 | 108 | 50 |
| **2037** | 2261 | 2452 | 2637 | 3442 | 2126 | 5170 | 2401 | 377 | 307 | 220 | 143 | 89 | 108 | 50 |
| **2038** | 2257 | 2448 | 2633 | 3436 | 2122 | 5161 | 2397 | 376 | 306 | 219 | 143 | 88 | 108 | 50 |
| **2039** | 2253 | 2444 | 2629 | 3430 | 2119 | 5152 | 2393 | 376 | 305 | 219 | 143 | 88 | 107 | 50 |
| **2040** | 2249 | 2440 | 2624 | 3424 | 2115 | 5144 | 2389 | 375 | 305 | 219 | 143 | 88 | 107 | 50 |
| **2041** | 2245 | 2436 | 2620 | 3418 | 2112 | 5135 | 2385 | 374 | 304 | 218 | 142 | 88 | 107 | 50 |
| **2042** | 2242 | 2432 | 2615 | 3412 | 2108 | 5126 | 2381 | 374 | 304 | 218 | 142 | 88 | 107 | 50 |
| **2043** | 2238 | 2427 | 2611 | 3406 | 2104 | 5117 | 2377 | 373 | 303 | 218 | 142 | 88 | 107 | 50 |
| **2044** | 2234 | 2423 | 2606 | 3401 | 2101 | 5109 | 2373 | 372 | 303 | 217 | 142 | 88 | 106 | 49 |
| **2045** | 2230 | 2419 | 2602 | 3395 | 2097 | 5100 | 2369 | 372 | 302 | 217 | 141 | 87 | 106 | 49 |
| **2046** | 2226 | 2415 | 2597 | 3389 | 2094 | 5091 | 2365 | 371 | 302 | 216 | 141 | 87 | 106 | 49 |
| **2047** | 2223 | 2411 | 2593 | 3383 | 2090 | 5083 | 2361 | 370 | 301 | 216 | 141 | 87 | 106 | 49 |
| **2048** | 2219 | 2407 | 2589 | 3378 | 2087 | 5074 | 2357 | 370 | 301 | 216 | 141 | 87 | 106 | 49 |
| **2049** | 2215 | 2403 | 2584 | 3372 | 2083 | 5065 | 2353 | 369 | 300 | 215 | 140 | 87 | 106 | 49 |
| **2050** | 2211 | 2399 | 2580 | 3366 | 2080 | 5057 | 2349 | 369 | 300 | 215 | 140 | 87 | 105 | 49 |

Apx Table B.7 Storage current cost data by source, total cost basis

| | $/kWh | | | | | $/kW | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Aurecon 2019-20 | Aurecon 2020-21 | Aurecon 2021-22 | GenCost 2019-20 | AEMO ISP Dec 2021 | Aurecon 2019-20 | Aurecon 2020-21 | Aurecon 2021-22 | GenCost 2019-20 | AEMO ISP Dec 2021 |
| **Battery (1hr)** | 1029 | 820 | 775 | - | | 1029 | 820 | 775 | - | - |
| **Battery (2hrs)** | 648 | 549 | 516 | - | | 1295 | 1099 | 1032 | - | - |
| **Battery (4hrs)** | 511 | 437 | 407 | - | | 2045 | 1747 | 1629 | - | - |
| **Battery (8hrs)** | 464 | 385 | 357 | - | | 3711 | 3082 | 2859 | - | - |
| **PHES (8hrs)** | - | - | - | 259 | 315 | - | - | - | 1994 | 2520 |
| **PHES (12hrs)** | - | - | - | 184 | 226 | - | - | - | 2118 | 2711 |
| **PHES (24hrs)** | - | - | - | 136 | 147 | - | - | - | 3139 | 3537 |
| **PHES (24hrs) Tasmania** | - | - | - | - | 91 | - | - | - | - | 2185 |
| **PHES (48hrs)** | - | - | - | 76 | 111 | - | - | - | 3517 | 5313 |
| **PHES (48hrs) Tasmania** | - | - | - | - | 51 | - | - | - | - | 2468 |

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1300/kWh (Aurecon, 2022).

### Apx Table B.8 Data assumptions for LCOE calculations

| | Constant | | | | | | Low assumption | | | High assumption | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Economic life | Construction time | Efficiency | O&M fixed | O&M variable | $CO_2$ storage | Capital | Fuel | Capacity factor | Capital | Fuel | Capacity factor |
| | Years | Years | | $/kW | $/MWh | $/MWh | $/kW | $/GJ | | $/kW | $/GJ | |
| **2021** | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 1.5 | 44% | 16.4 | 7.2 | 1.9 | 4011 | 9.7 | 80% | 4011 | 13.0 | 60% |
| **Gas combined cycle** | 25 | 1.5 | 51% | 10.9 | 3.7 | 0.0 | 1559 | 9.7 | 80% | 1559 | 13.0 | 60% |
| **Gas open cycle (small)** | 25 | 1.3 | 36% | 12.6 | 12.0 | 0.0 | 1290 | 9.7 | 20% | 1290 | 13.0 | 20% |
| **Gas open cycle (large)** | 25 | 1.1 | 33% | 10.2 | 7.3 | 0.0 | 873 | 9.7 | 20% | 873 | 13.0 | 20% |
| **Gas reciprocating** | 25 | 1.0 | 41% | 24.1 | 7.6 | 0.0 | 1635 | 9.7 | 20% | 1635 | 13.0 | 20% |
| **Hydrogen reciprocating** | 25 | 1.0 | 32% | 33.0 | 0.0 | 0.0 | 1989 | 14.6 | 20% | 1989 | 21.9 | 20% |
| **Black coal with CCS** | 30 | 2.0 | 30% | 77.8 | 8.0 | 4.1 | 9077 | 2.0 | 80% | 9077 | 3.1 | 60% |
| **Black coal** | 30 | 2.0 | 40% | 53.2 | 4.2 | 0.0 | 4343 | 2.0 | 80% | 4343 | 3.1 | 60% |
| **Brown coal** | 30 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 6704 | 0.6 | 80% | 6704 | 0.7 | 60% |
| **Biomass (small scale)** | 30 | 1.3 | 29% | 131.6 | 8.4 | 0.0 | 6954 | 0.5 | 80% | 6954 | 2.0 | 60% |
| **Large scale solar PV** | 30 | 0.5 | 100% | 17.0 | 0.0 | 0.0 | 1441 | 0.0 | 32% | 1441 | 0.0 | 22% |
| **Solar thermal (12hrs)** | 25 | 1.8 | 100% | 120.0 | 0.0 | 0.0 | 6693 | 0.0 | 52% | 6693 | 0.0 | 42% |
| **Wind onshore** | 25 | 1.0 | 100% | 25.0 | 0.0 | 0.0 | 1960 | 0.0 | 44% | 1960 | 0.0 | 35% |
| **Wind offshore** | 25 | 3.0 | 100% | 149.9 | 0.0 | 0.0 | 4649 | 0.0 | 52% | 4649 | 0.0 | 40% |
| **2030** | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 1.5 | 44% | 16.4 | 7.2 | 1.9 | 3784 | 9.4 | 80% | 3957 | 16.8 | 60% |
| **Gas combined cycle** | 25 | 1.5 | 51% | 10.9 | 3.7 | 0.0 | 1511 | 9.4 | 80% | 1516 | 16.8 | 60% |
| **Gas open cycle (small)** | 25 | 1.3 | 36% | 12.6 | 12.0 | 0.0 | 1250 | 9.4 | 20% | 1254 | 16.8 | 20% |
| **Gas open cycle (large)** | 25 | 1.1 | 33% | 10.2 | 7.3 | 0.0 | 741 | 9.4 | 20% | 741 | 16.8 | 20% |
| **Gas reciprocating** | 25 | 1.0 | 41% | 24.1 | 7.6 | 0.0 | 1584 | 9.4 | 20% | 1590 | 16.8 | 20% |
| **Hydrogen reciprocating** | 25 | 1.0 | 32% | 33.0 | 0.0 | 0.0 | 1927 | 14.6 | 20% | 1934 | 21.9 | 20% |
| **Black coal with CCS** | 30 | 2.0 | 30% | 77.8 | 8.0 | 4.1 | 8747 | 2.3 | 80% | 8884 | 4.0 | 60% |
| **Black coal** | 30 | 2.0 | 40% | 53.2 | 4.2 | 0.0 | 4208 | 2.3 | 80% | 4223 | 4.0 | 60% |
| **Brown coal** | 30 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 6495 | 0.7 | 80% | 6518 | 0.7 | 60% |
| **Biomass (small scale)** | 30 | 1.3 | 29% | 131.6 | 8.4 | 0.0 | 6949 | 0.5 | 80% | 6954 | 2.0 | 60% |
| **Nuclear (SMR)** | 30 | 3.0 | 35% | 200.0 | 5.3 | 0.0 | 7904 | 0.5 | 80% | 16773 | 0.7 | 60% |
| **Large scale solar PV** | 30 | 0.5 | 100% | 17.0 | 0.0 | 0.0 | 785 | 0.0 | 32% | 1013 | 0.0 | 19% |
| **Solar thermal (12hrs)** | 25 | 1.8 | 100% | 120.0 | 0.0 | 0.0 | 4657 | 0.0 | 52% | 5660 | 0.0 | 42% |
| **Wind onshore** | 25 | 1.0 | 100% | 25.0 | 0.0 | 0.0 | 1633 | 0.0 | 46% | 1897 | 0.0 | 35% |
| **Wind offshore** | 25 | 3.0 | 100% | 149.9 | 0.0 | 0.0 | 2967 | 0.0 | 54% | 4545 | 0.0 | 40% |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2040** | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 1.5 | 44% | 16.4 | 7.2 | 1.9 | 3276 | 9.4 | 80% | 3892 | 17.9 | 60% |
| **Gas combined cycle** | 25 | 1.5 | 51% | 10.9 | 3.7 | 0.0 | 1459 | 9.4 | 80% | 1464 | 17.9 | 60% |
| **Gas open cycle (small)** | 25 | 1.3 | 36% | 12.6 | 12.0 | 0.0 | 1207 | 9.4 | 20% | 1211 | 17.9 | 20% |
| **Gas open cycle (large)** | 25 | 1.1 | 33% | 10.2 | 7.3 | 0.0 | 716 | 9.4 | 20% | 716 | 17.9 | 20% |
| **Gas reciprocating** | 25 | 1.0 | 41% | 24.1 | 7.6 | 0.0 | 1530 | 9.4 | 20% | 1535 | 17.9 | 20% |
| **Hydrogen reciprocating** | 25 | 1.0 | 32% | 33.0 | 0.0 | 0.0 | 1861 | 11.6 | 20% | 1867 | 17.4 | 20% |
| **Black coal with CCS** | 30 | 2.0 | 30% | 77.8 | 8.0 | 4.1 | 8025 | 1.8 | 80% | 8650 | 4.0 | 60% |
| **Black coal** | 30 | 2.0 | 40% | 53.2 | 4.2 | 0.0 | 4063 | 1.8 | 80% | 4078 | 4.0 | 60% |
| **Brown coal** | 30 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 6272 | 0.7 | 80% | 6294 | 0.7 | 60% |
| **Biomass (small scale)** | 30 | 1.3 | 29% | 131.6 | 8.4 | 0.0 | 6682 | 0.5 | 80% | 6954 | 2.0 | 60% |
| **Nuclear (SMR)** | 30 | 3.0 | 40% | 200.0 | 5.3 | 0.0 | 7806 | 0.5 | 80% | 16773 | 0.7 | 60% |
| **Large scale solar PV** | 30 | 0.5 | 100% | 17.0 | 0.0 | 0.0 | 578 | 0.0 | 32% | 733 | 0.0 | 19% |
| **Solar thermal (12hrs)** | 25 | 1.8 | 100% | 120.0 | 0.0 | 0.0 | 3620 | 0.0 | 52% | 4894 | 0.0 | 42% |
| **Wind onshore** | 25 | 1.0 | 100% | 25.0 | 0.0 | 0.0 | 1553 | 0.0 | 48% | 1868 | 0.0 | 35% |
| **Wind offshore** | 25 | 3.0 | 100% | 149.9 | 0.0 | 0.0 | 2653 | 0.0 | 57% | 4482 | 0.0 | 40% |
| **2050** | | | | | | | | | | | | |
| **Gas with CCS** | 25 | 1.5 | 44% | 16.4 | 7.2 | 1.9 | 2978 | 9.4 | 80% | 3324 | 17.9 | 60% |
| **Gas combined cycle** | 25 | 1.5 | 51% | 10.9 | 3.7 | 0.0 | 1411 | 9.4 | 80% | 1413 | 17.9 | 60% |
| **Gas open cycle (small)** | 25 | 1.3 | 36% | 12.6 | 12.0 | 0.0 | 1167 | 9.4 | 20% | 1169 | 17.9 | 20% |
| **Gas open cycle (large)** | 25 | 1.1 | 33% | 10.2 | 7.3 | 0.0 | 691 | 9.4 | 20% | 691 | 17.9 | 20% |
| **Gas reciprocating** | 25 | 1.0 | 41% | 24.1 | 7.6 | 0.0 | 1480 | 9.4 | 20% | 1482 | 17.9 | 20% |
| **Hydrogen reciprocating** | 25 | 1.0 | 32% | 33.0 | 0.0 | 0.0 | 1800 | 10.2 | 20% | 1803 | 15.3 | 20% |
| **Black coal with CCS** | 30 | 2.0 | 30% | 77.8 | 8.0 | 4.1 | 7552 | 1.8 | 80% | 7958 | 4.0 | 60% |
| **Black coal** | 30 | 2.0 | 40% | 53.2 | 4.2 | 0.0 | 3930 | 1.8 | 80% | 3937 | 4.0 | 60% |
| **Brown coal** | 30 | 4.0 | 32% | 69.0 | 5.3 | 0.0 | 6066 | 0.7 | 80% | 6077 | 0.7 | 60% |
| **Biomass (small scale)** | 30 | 1.3 | 29% | 131.6 | 8.4 | 0.0 | 6517 | 0.5 | 80% | 6954 | 2.0 | 60% |
| **Nuclear (SMR)** | 30 | 3.0 | 45% | 200.0 | 5.3 | 0.0 | 7806 | 0.5 | 80% | 16773 | 0.7 | 60% |
| **Large scale solar PV** | 30 | 0.5 | 100% | 17.0 | 0.0 | 0.0 | 521 | 0.0 | 32% | 644 | 0.0 | 19% |
| **Solar thermal (12hrs)** | 25 | 1.8 | 100% | 120.0 | 0.0 | 0.0 | 2911 | 0.0 | 52% | 4103 | 0.0 | 42% |
| **Wind onshore** | 25 | 1.0 | 100% | 25.0 | 0.0 | 0.0 | 1521 | 0.0 | 50% | 1828 | 0.0 | 35% |
| **Wind offshore** | 25 | 3.0 | 100% | 149.9 | 0.0 | 0.0 | 2506 | 0.0 | 61% | 4431 | 0.0 | 40% |

Notes: Wind is onshore. Large-scale solar PV is single axis tracking. The discount rate used for all technologies is 5.99% unless a risk premium of 5% is added.

Apx Table B.9 Electricity generation technology LCOE projections data, 2021-22 $/MWh

| Category | Assumption | Technology | 2021 | | 2030 | | 2040 | | 2050 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Low | High | Low | High | Low | High | Low | High |
| **Peaking 20% load** | | Gas turbine small | 178 | 211 | 173 | 248 | 172 | 257 | 170 | 255 |
| | | Gas turbine large | 160 | 195 | 150 | 230 | 149 | 241 | 148 | 239 |
| | | Gas reciprocating | 184 | 213 | 179 | 245 | 177 | 251 | 174 | 249 |
| | | $H_2$ reciprocating | 277 | 359 | 274 | 357 | 237 | 303 | 219 | 276 |
| **Flexible 60-80% load, high emission** | | Black coal | 81 | 109 | 81 | 116 | 75 | 113 | 73 | 111 |
| | | Brown coal | 110 | 143 | 108 | 140 | 105 | 136 | 103 | 133 |
| | | Gas | 93 | 123 | 90 | 149 | 90 | 156 | 89 | 155 |
| | Climate policy risk premium | Black coal | 118 | 159 | 118 | 164 | 110 | 160 | 107 | 156 |
| | | Brown coal | 189 | 248 | 184 | 242 | 179 | 236 | 174 | 228 |
| | | Gas | 105 | 139 | 101 | 165 | 101 | 171 | 100 | 170 |
| **Flexible 60-80% load, low emission** | | Black coal with CCS | 153 | 204 | 153 | 213 | 138 | 209 | 132 | 198 |
| | | Gas with CCS | 140 | 184 | 134 | 214 | 129 | 222 | 125 | 213 |
| | | Solar thermal 12hrs | 153 | 190 | 115 | 166 | 95 | 148 | 82 | 129 |
| | | Nuclear (SMR) | | | 136 | 326 | 135 | 325 | 134 | 325 |
| | | Biomass (small scale) | 111 | 162 | 111 | 162 | 108 | 162 | 106 | 162 |
| **Variable** | Standalone | Solar PV | 44 | 65 | 27 | 56 | 21 | 43 | 20 | 39 |
| | | Wind onshore | 49 | 61 | 40 | 59 | 37 | 59 | 34 | 58 |
| | | Wind offshore | 128 | 166 | 90 | 163 | 79 | 162 | 72 | 160 |
| **Variable with integration costs** | Wind & solar PV combined | 60% share | | | 53 | 73 | | | | |
| | | 70% share | | | 55 | 76 | | | | |
| | | 80% share | | | 58 | 79 | | | | |
| | | 90% share | | | 61 | 82 | | | | |

Apx Table B.10 Hydrogen electrolyser cost projections by scenario and technology, $/kW

| | Current policies | | Global NZE by 2050 | | Global NZE post 2050 | |
|---|---|---|---|---|---|---|
| | Alkaline | PEM | Alkaline | PEM | Alkaline | PEM |
| **2021** | 1650 | 2700 | 1650 | 2770 | 1650 | 2700 |
| **2022** | 1513 | 2501 | 1333 | 2446 | 1378 | 2438 |
| **2023** | 1400 | 2316 | 1083 | 2160 | 1199 | 2201 |
| **2024** | 1306 | 2145 | 912 | 1907 | 1070 | 1987 |
| **2025** | 1225 | 1987 | 787 | 1684 | 972 | 1794 |
| **2026** | 1156 | 1841 | 695 | 1487 | 896 | 1620 |
| **2027** | 1098 | 1705 | 618 | 1313 | 833 | 1463 |
| **2028** | 1024 | 1579 | 559 | 1159 | 768 | 1321 |
| **2029** | 981 | 1463 | 514 | 1023 | 727 | 1193 |
| **2030** | 918 | 1355 | 472 | 904 | 673 | 1077 |
| **2031** | 885 | 1255 | 439 | 798 | 620 | 972 |
| **2032** | 829 | 1162 | 412 | 704 | 576 | 878 |
| **2033** | 798 | 1077 | 388 | 622 | 554 | 793 |
| **2034** | 769 | 997 | 367 | 549 | 535 | 716 |
| **2035** | 746 | 924 | 348 | 485 | 517 | 646 |
| **2036** | 719 | 855 | 330 | 428 | 481 | 583 |
| **2037** | 700 | 792 | 313 | 378 | 453 | 527 |
| **2038** | 675 | 734 | 298 | 334 | 430 | 476 |
| **2039** | 660 | 680 | 281 | 295 | 407 | 429 |
| **2040** | 630 | 630 | 260 | 260 | 388 | 388 |
| **2041** | 614 | 614 | 241 | 241 | 372 | 372 |
| **2042** | 591 | 591 | 226 | 226 | 358 | 358 |
| **2043** | 575 | 575 | 214 | 214 | 346 | 346 |
| **2044** | 557 | 557 | 204 | 204 | 332 | 332 |
| **2045** | 542 | 542 | 193 | 193 | 319 | 319 |
| **2046** | 518 | 518 | 182 | 182 | 308 | 308 |
| **2047** | 489 | 489 | 173 | 173 | 298 | 298 |
| **2048** | 467 | 467 | 165 | 165 | 289 | 289 |
| **2049** | 450 | 450 | 159 | 159 | 280 | 280 |
| **2050** | 426 | 426 | 147 | 147 | 265 | 265 |

# Appendix C Technology inclusion principles

GenCost is not designed to be a comprehensive source of technology information. To manage the cost and timeliness of the project, we reserve the right to target our efforts on only those technologies we expect to be material, or that are otherwise informative. However, the range of potential futures is broad and as a result there is uncertainty about what technologies we need to include.

The following principles are proposed to provide the project with more guidance on considerations for including technology options.

## C.1 Relevant to generation sector futures

The technology must have the potential to be deployed at significant scale now or in the future and is a generation technology, a supporting technology or otherwise could significantly impact the generation sector. The broad categories that are currently considered relevant are:

- Generation technologies
- Storage technologies
- Hydrogen technologies
- Consumer scale technologies (e.g., rooftop solar, batteries).

Auxiliary technologies such as synchronous condensers, statcoms and grid forming inverters are also relevant and important but their inclusion in energy system models is not common or standardised due to the limited representation of power quality issues in most electricity models. Where they have been included, results indicate they may not be financially significant enough to warrant inclusion. Also, inverters, which are relevant for synthetic inertia, are not distinct from some generation technologies which creates another challenge.

## C.2 Transparent Australian data outputs are not available from other sources

Examples of technologies for which Australian data is already available from other sources includes:

- Operating generation technologies (i.e., specific information on projects that have already been deployed)
- Retrofit generation projects
- New build transmission.

Most of these are provided through separate AEMO processes.

Other organisations publish information for new build Australian technologies but not with an equivalent level of transparency and consultation. New build cost projections also require more complex methodologies than observing the characteristics of existing projects. There is a distinct lack of transparency around these projection methodologies. Hence, the focus of GenCost is on new build technologies.

## C.3 Has the potential to be either globally or domestically significant

A technology is significant if it can find a competitive niche in a domestic or global electricity market, and therefore has the potential to reach a significant scale of development.

Technologies can fall into four possible categories. Any technology that is neither globally nor domestically significant will not be included anywhere. Any other combination should be included in the global modelling. However, we may only choose to include domestically significant technologies in the current cost update which is subcontracted to an engineering firm.

**Apx Table C.1 Examples of considering global or domestic signficance**

| Globally significant | Domestically significant | Examples |
| --- | --- | --- |
| **Yes** | Yes | **Solar PV**, **onshore and offshore wind** |
| **Yes** | No | **New large-scale hydro**. No significant new sites expected to be developed in Australia<br>**Conventional geothermal energy**: Australia is relatively geothermally inactive<br>**Large scale nuclear**: scale is unsuitable |
| **No** | Yes | None currently. A previous example was **enhanced geothermal,** but economics have meant there is no current domestic interest in this technology |
| **No** | No | Emerging technologies that have yet to receive commercial interest (e.g**., fusion**) or have no commercial prospects due to changing circumstances (e.g., **new brown coal**) |

## C.4 Input data quality level is reasonable

Input data quality types generally fall into 5 categories in order of highest (A) to lowest (E) confidence in Australian costs

A. Domestically observable projects (this might be through public data or data held by engineering and construction firms)

B. Extrapolations of domestic or global projects (e.g., observed 2-hour battery re-costed to a 4-hour battery, gas reciprocating engine extrapolated to a hydrogen reciprocating engine)

C. Globally observable projects

D. Broadly accepted costing software (e.g., ASPEN)

E. “Paper” studies (e.g., industry and academic reports and articles)

While paper studies are least preferred and would normally be rejected, where we need to include a technology because of its potential to be globally or domestically significant in the future, and that technology only has paper studies available as the highest quality available, then we will use paper studies. We will not use confidential data as a primary information source since by definition they cannot be validated by stakeholders. However, confidential sources could provide some guidance to interpreting public sources.

## C.5 Mindful of model size limits in technology specificity

Owing to model size limits, we are mindful of not getting too specific about technologies but achieving good predictive power (called model parsimony). We often choose:

- A single set of parameters to represent a broad class (e.g., selecting the most common size)
- A leading design where there are multiple available (e.g., solar thermal tower has been selected over dish or linear Fresnel or single axis tracking solar PV over flat)

The approach to a technology’s specificity may be reviewed with feedback from stakeholders (e.g., two sizes of gas turbines have been added over time). For a technology like storage, it has been necessary to include multiple durations for each storage as this property is too important to generalise. As it becomes clearer what the competitive duration niche is for each type of storage technology, it will be desirable to remove some durations. It might also be possible to generalise across storage technologies if their costs at some durations is similar.

# Shortened forms

| Abbreviation | Meaning |
|---|---|
| **ABS** | Australian Bureau of Statistics |
| **AE** | Alkaline electrolysis |
| **AEMO** | Australian Energy Market Operator |
| **APGT** | Australian Power Generation Technology |
| **BAU** | Business as usual |
| **BOP** | Balance of plant |
| **CCS** | Carbon capture and storage |
| **CCUS** | Carbon capture, utilisation and storage |
| **CHP** | Combined heat and power |
| **$CO_2$** | Carbon dioxide |
| **CSIRO** | Commonwealth Scientific and Industrial Research Organisation |
| **CSP** | Concentrated solar power |
| **EV** | Electric vehicle |
| **GALLM** | Global and Local Learning Model |
| **GALLME** | Global and Local Learning Model Electricity |
| **GALLMT** | Global and Local Learning Model Transport |
| **GJ** | Gigajoule |
| **GW** | Gigawatt |
| **hrs** | Hours |
| **IEA** | International Energy Agency |
| **IGCC** | Integrated gasification combined cycle |
| **ISP** | Integrated System plan |
| **kW** | Kilowatt |
| **kWh** | Kilowatt hour |
| **LCOE** | Levelised Cost of Electricity |
| **LCV** | Light commercial vehicle |

| Abbreviation | Meaning |
|---|---|
| **MCV** | Medium commercial vehicle |
| **Li-ion** | Lithium-ion |
| **LR** | Learning Rate |
| **Mt** | Million tonnes |
| **MW** | Megawatt |
| **MWh** | Megawatt hour |
| **NEM** | National Electricity Market |
| **NZE** | Net zero emissions |
| **O&M** | Operations and Maintenance |
| **OECD** | Organisation for Economic Cooperation and Development |
| **PEM** | Proton-exchange membrane electrolysis |
| **pf** | Pulverised fuel |
| **PHES** | Pumped hydro energy storage |
| **PV** | Photovoltaic |
| **REZ** | Renewable Energy Zone |
| **SDS** | Sustainable Development Scenario |
| **SMR** | Small modular reactor |
| **STEPS** | Stated Policies |
| **SWIS** | South-West Interconnected System |
| **TWh** | Terawatt hour |
| **VPP** | Virtual Power Plant |
| **VRE** | Variable Renewable Energy |
| **WEO** | World Energy Outlook |

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