Australia's National
Science Agency

GenCost 2022-23

Consultation draft

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Consultation process

This report is provided as one of several documents supporting AEMO's December 2022 consultation on its most recent Inputs, Assumptions and Scenarios Report (IASR). For details of how to submit feedback, go to AEMO | Current and closed consultations. Feedback received will be used to improve content and produce a final GenCost 2022-23 report in the second quarter of 2023.

Acknowledgments

Parts of this report were shared with stakeholders in an October 2022 webinar for initial feedback. The authors are grateful for all feedback received.

Executive summary

Technological change in electricity generation is a global effort that is strongly linked to global climate change policy ambitions. Following COP27 in Sharm el-Sheikh, world leaders reaffirmed their support for limiting global average temperature rise to 1.5 degrees Celsius. At a domestic level, the commonwealth government, together with all Australian states and territories aspire to or have legislated net zero emissions (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.

GenCost update

GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating the costs of electricity generation, energy storage and hydrogen production with a strong emphasis on stakeholder engagement. GenCost represents Australia's most comprehensive electricity generation cost forecasting report. It uses the best available information each cycle to provide an objective annual benchmark on cost projections and updates forecasts accordingly to help to guide decision making, given electricity costs change significantly each year This is the fifth update following the inaugural report in 2018.

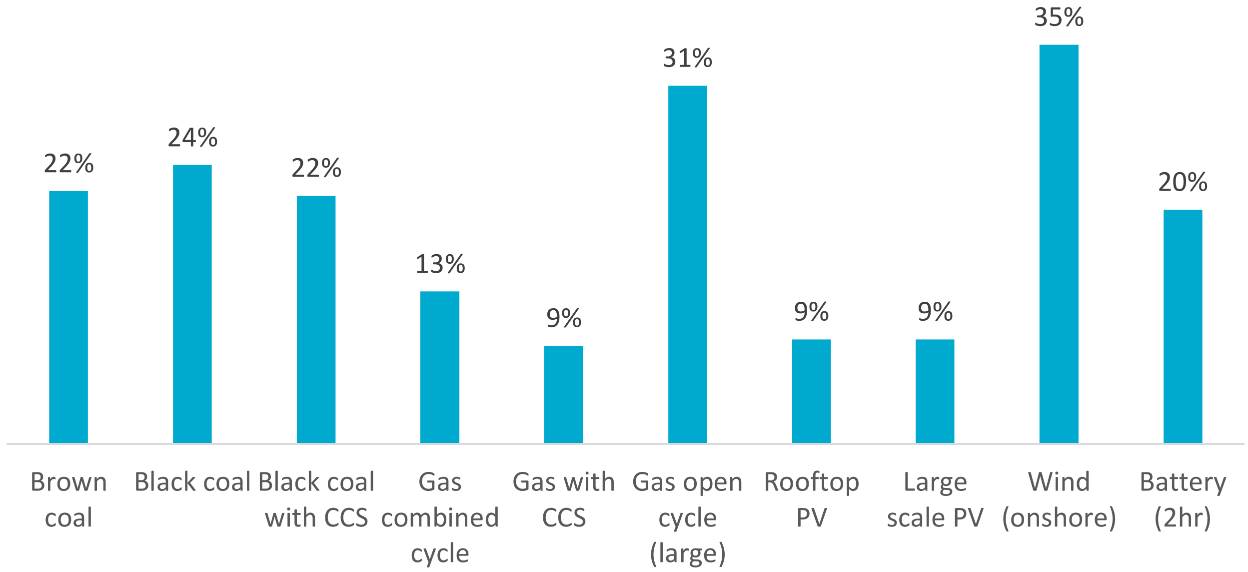
Technology costs are one piece of the puzzle. They are an important input to electricity sector analysis which is why we are providing this consultation draft to seek input on the updated data and projections.

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.

Global inflationary pressures

The COVID-19 pandemic has resulted in global supply chain constraints which have impacted the prices of raw materials needed in technology manufacturing and in freight costs. As a result, the capital costs of all technologies which are currently being considered for construction have increased and Aurecon has provided data on the new cost levels. For technologies which are not currently being deployed, we assume their costs would also have increased had contracts for construction been entered into. We estimate the likely cost increase for these technologies based on increases in the costs of inputs they would require in their construction and installation. The data sourced for these calculations include price indices for consumer goods and services, imported equipment, domestic equipment and labour. We combine this information with data on their local content, imported content and installation share of costs.

The data indicates that compared to 2021-22 data, technology costs have increased 20% on average but with significant diversity. Costs increase are as low as 9% for solar PV and up to 35% for wind. The difference in cost increases mostly reflects differences in material inputs and exposure to freight costs. Some variation may also represent the extent to which cost increases had already flowed through to the previous year's estimate as we consider the beginning of this inflationary cycle to have started in 2020. Whilst prices had not risen in 2020, it appears cost reductions had started to slow from that time for some technologies.



ES Figure 0-1 Increase in current costs of selected technologies relative to GenCost 2021-22

The inflationary cycle is assumed to be at its peak in 2022 and 2023 and to take until 2027 to return to normal costs[1]. Forecasts of the input price indices are used to shape the profile of cost reductions to 2027 as global inflationary pressures unwind. After 2027, our standard projection methodologies are resumed.

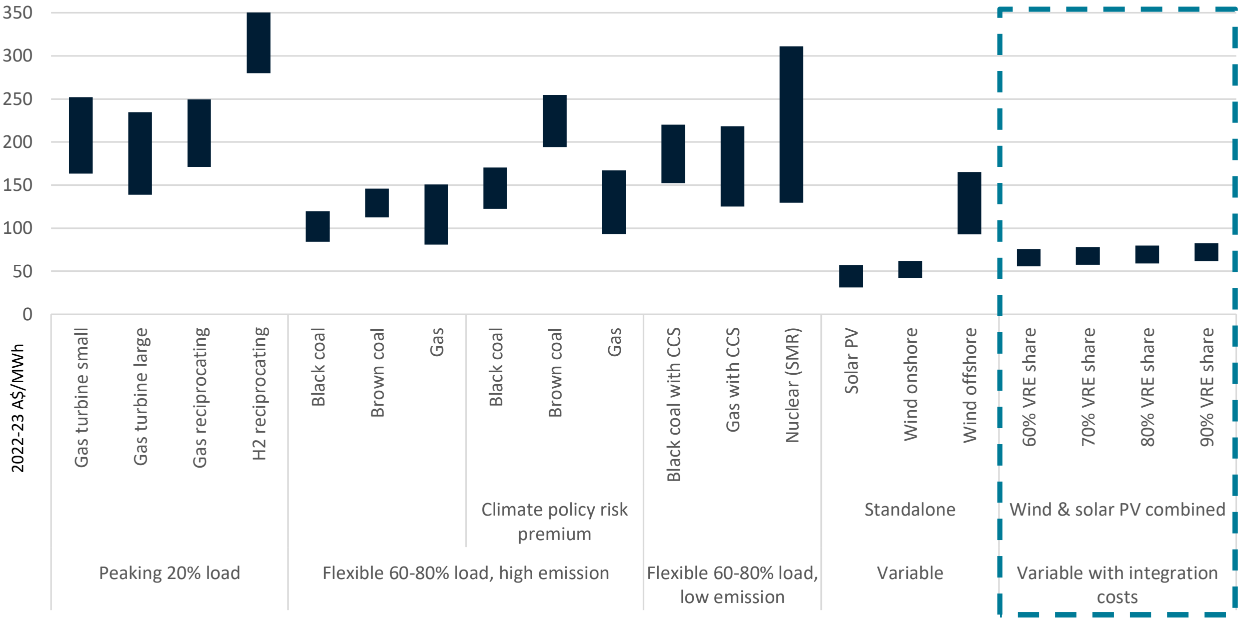
Levelised cost of electricity

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. However, an additional process is undertaken to calculate the integration costs of variable renewables.

[1] This trajectory is based on published forecasts of the Reserve Bank of Australia regard to general inflation and information presented at the 26th October AEMO Forecasting Reference Group on the outlook for fuel prices.

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%[2] 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 $25/MWh depending on the VRE share. The key costs for supporting reliable supply of electricity under high shares of variable renewable electricity are additional transmission, storage and peaking gas capacity.

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.



ES Figure 0-2 Calculated LCOE by technology and category for 2030

[2] 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 55% will be achieved in 2030 without any new policies (excluding Northern Territory).

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 (2022a) 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[3].

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 resources. AEMO commissioned Aurecon to provide an update of current electricity generation and storage cost and performance characteristics (Aurecon, 2022a). Earlier drafts of Aurecon's data were initially shared with stakeholders during a webinar in October 2022.

[3] 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, our main priority has been to understand how current inflationary pressures are impacting the short-term outlook for technology costs. We have implemented a change to our methodology up to the year 2027 to capture these short-term drivers.

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

A set of technology selection principles has been included in Appendix C. Feedback on these principles is always welcome.

1.6 Overview of feedback received

1.6.1 Following up on feedback from GenCost 2021-22

We have received feedback from the biomass and solar thermal industries that their technologies were not being represented in a way that reflected how those technologies were likely to be deployed. In regard to biomass, it was requested that the technology should include waste heat utilisation. For solar thermal, we are advised that this technology is likely to be configured with a greater emphasis on nighttime generation. These technologies have been adjusted in the Aurecon (2022a) report and those changes flowed through to this GenCost report.

1.6.2 October 2022 webinar

At the October webinar it was noted that the impact of inflationary pressures on technologies that are not currently being built could not be observed but this needs to be addressed. As a result, CSIRO developed a method and there are more details on our approach in the body of this report

1.6.3 Energy Policy Institute of Australian policy paper 3/2022

On 23rd September 2022 the Energy Policy Institute of Australia (EPIA) publicly released a paper called *Future Australian Electricity Generation Costs – A review of CSIRO's GenCost 2021-22 Report*[4]. GenCost receives uninvited input and questions from stakeholders throughout the year outside of our planned stakeholder engagement processes. Stakeholders are encouraged to continue providing input - both invited and uninvited. We typically provide a summary of feedback received throughout the year and how it has been incorporated. However, the depth of input received in the EPIA paper is beyond what a summary could adequately address. Therefore, in this case, GenCost has provided a more detailed response in the form of a short report which is available at: https://publications.csiro.au/publications/publication/PIcsiro:EP2022-5083.

[4] At the time of writing, the EPIA report was available at this link: http://energypolicyinstitute.com.au/images/3-22_EPIA_-_Future_Australian_Electricity_Generation_Costs.pdf

2 Current technology costs

2.1 Current cost definition

Our definition of current capital costs are current contracting costs or 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 potential projects 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 or contracted in that year. Quotes received now for projects without a contracted delivery date 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 – such quotes should not be compared with current costs in this report but with future projections.

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 (2022a). Aurecon (2022a) 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 Capital cost source

AEMO commissioned Aurecon (2022a) to provide an update of current cost and performance data for existing and selected new electricity generation, storage and hydrogen production technologies. We have used data supplied by Aurecon (2022a) which is consistent with either the beginning of financial year 2022-23 or middle of 2022. Aurecon provides several measures of project capacity. We use the not-summer rating to determine $/kW costs.

Technologies not included in Aurecon (2022a) are typically those which are not being deployed in Australia but are otherwise of interest for modelling purposes. For these other technologies we have applied an inflationary factor to last year's estimate based on a bundle of consumer price

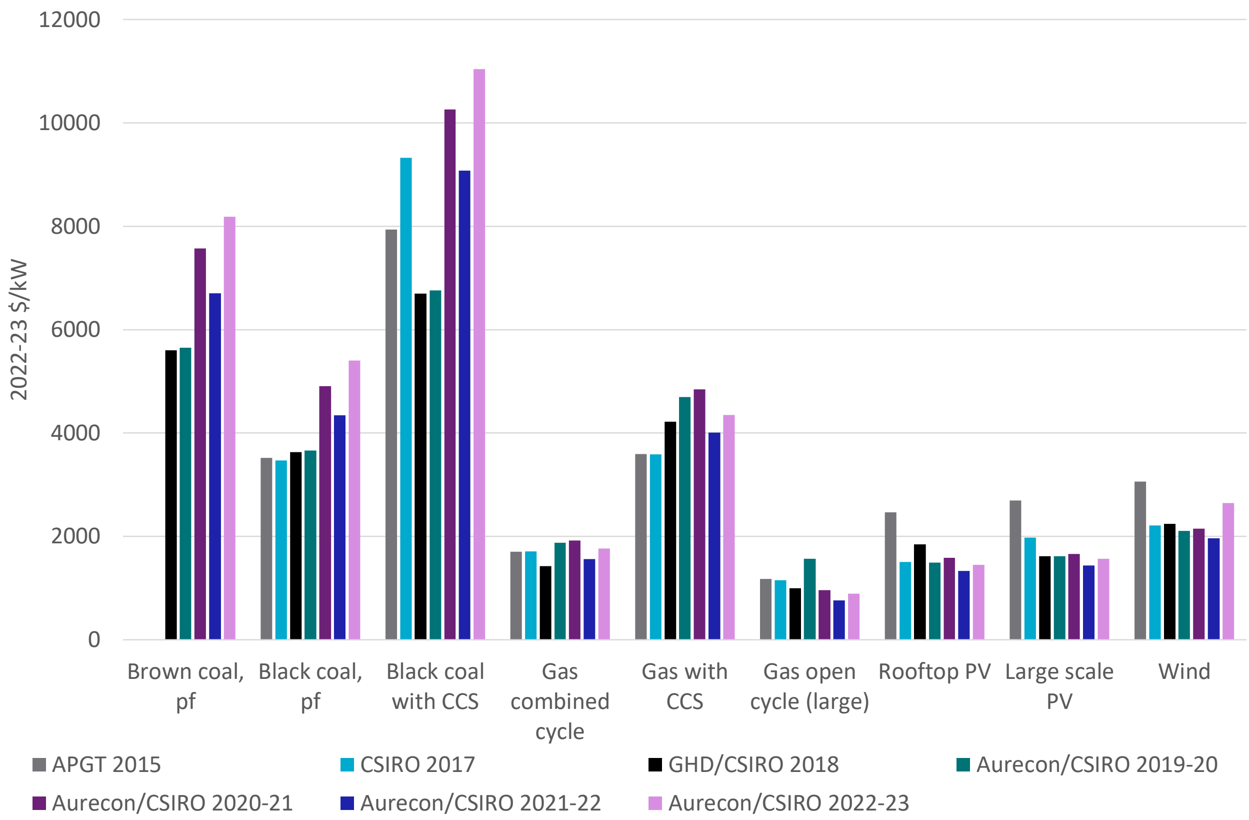
[5] This is not strictly true of all models but is most true of long-term investment models. In other models, investment costs are converted to an annuity (adjusted for different economic lifetimes), or additional capital costs may be added later in a project timeline for replacement of key components.

indices applied to knowledge of the relative mix of imported and local content for each technology.

Pumped hydro has also not been updated by Aurecon (2022a), but we have revised this data to be mostly consistent with AEMO's June 2022 ISP Input and Assumptions Workbook. CSIRO has modified AEMO's data for the years 2022 to 2027 to include the same inflationary effects as other mature technologies. Nuclear SMR current costs are not reported since there is no prospect of a plant being deployed in Australia 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.

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2022-23) cost estimates (drawing primarily on the Aurecon (2022a) update) for electricity generation technologies with those from previous years: GenCost 2018 to GenCost 2021-22 (which are a combination of Aurecon (2021, 2022b), GHD and CSIRO data), Hayward and Graham (2017) (also CSIRO) and CO2CRC (2015) which we refer to as APGT (short for Australian Power Generation Technology report).



[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.

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

All costs are expressed in real 2022-23 Australian dollars and represent overnight costs. Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme.

Whilst there had been some steady declines over the years for technologies such as solar PV and wind, for 2022-23, there has been an increase in capital costs impacting all technologies. The source of this increase is a combination of global supply chain constraints following the COVID-19 pandemic which has increased freight and raw material costs. The cost increase has not been uniform as shown in Figure 2-2 which is the percentage increase in capital costs by technology relative to 2021-22.

The increase in capital costs for gas technologies, wind and solar PV are from observation by Aurecon (2022a) of projects reaching financial close. The exception is Australian gas with CCS projects. Cost increases for this technology category are inferred from the gas technologies without CCS.

The increase in capital costs for black coal technologies has been calculated by CSIRO based on a bundle of consumer price indices applied to knowledge of the relative mix of imported and local content for each technology.

Overall, the differences in cost increases reflect different levels of exposure to increases in cost inputs. However, there is higher uncertainty about the impact of current inflationary pressure for those technologies not currently being deployed. Some variation may also represent the extent to which cost increases had already flowed through to the previous year's estimate as we consider the beginning of this inflationary cycle to have started in 2020. Whilst prices had not risen in 2020, it appears cost reductions had started to slow from that time for some technologies.

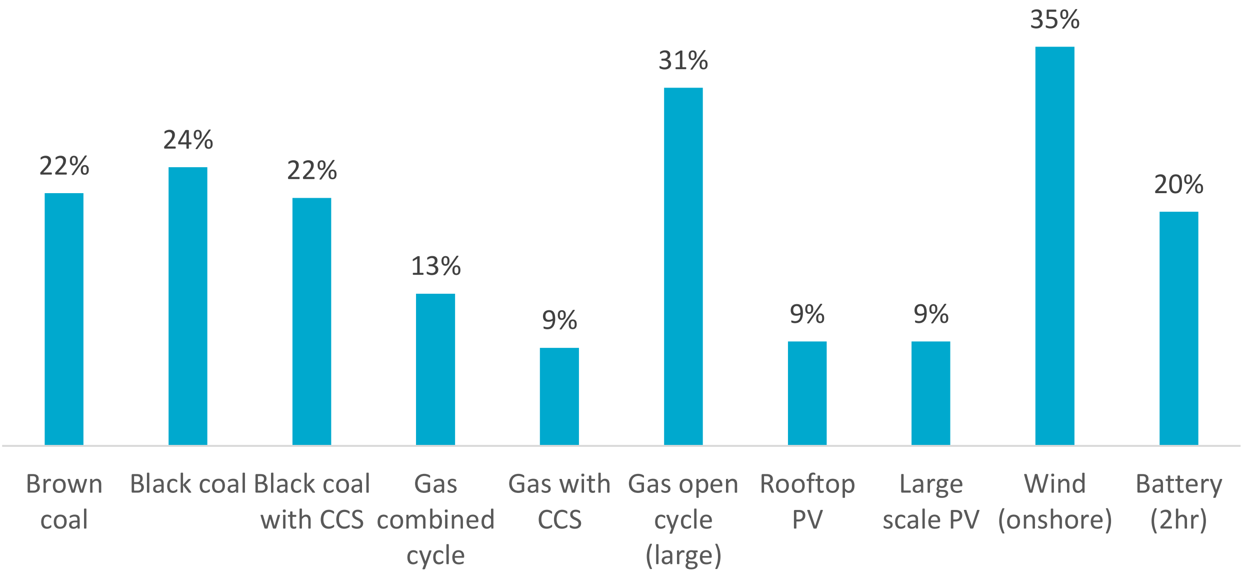


Figure 2-2 Annual increase in capital costs by technology

2.4 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 2-3). 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 additional power capacity to the project (Figure 2-4). 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).

[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.

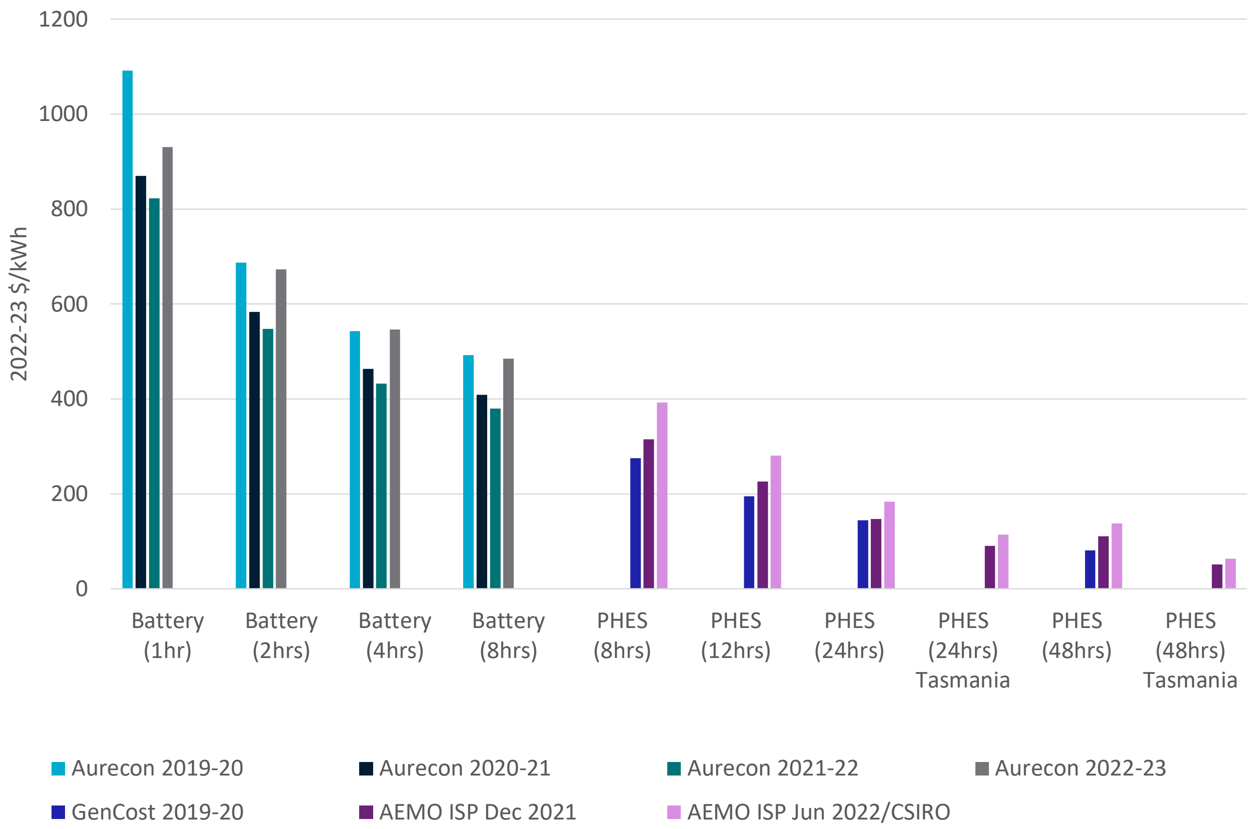


Figure 2-3 Capital costs of storage technologies in $/kWh (total cost basis)

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%[9]. Aurecon (2022a) 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 6% lower battery cost for a 1-hour duration battery, scaling down to a 1% cost reduction for 8 hours duration. PHES is more difficult to co-locate.

Like the generation technologies the current capital costs of the storage technologies have both increased. Battery costs (battery and balance of plant in total) have increased by 13% for one hour duration batteries and up to 28% for eight hour duration batteries. The higher increase for longer duration batteries indicates that the cost of the battery pack has been the greater source of cost increases compared to the inverter and other balance of plant components.

PHES current cost estimates have increased by 17% and the rate of increase is not assumed to vary significantly by duration. These increases are based on a bundled consumer price increase approach and are therefore less certain. Ordinarily, besides inflationary pressures, PHES 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

[9] The batteries in this publication have additional capacity which is not usable (e.g., there is typically a minimum 20% state of charge). This unusable capacity is not counted in the capacity of the battery or in any expression of its costs. When other publications include this unusable capacity the depth of discharge is less than 100%.

influence of site costs, we have included the cost of Tasmania pumped hydro for 24 and 48 hours duration.

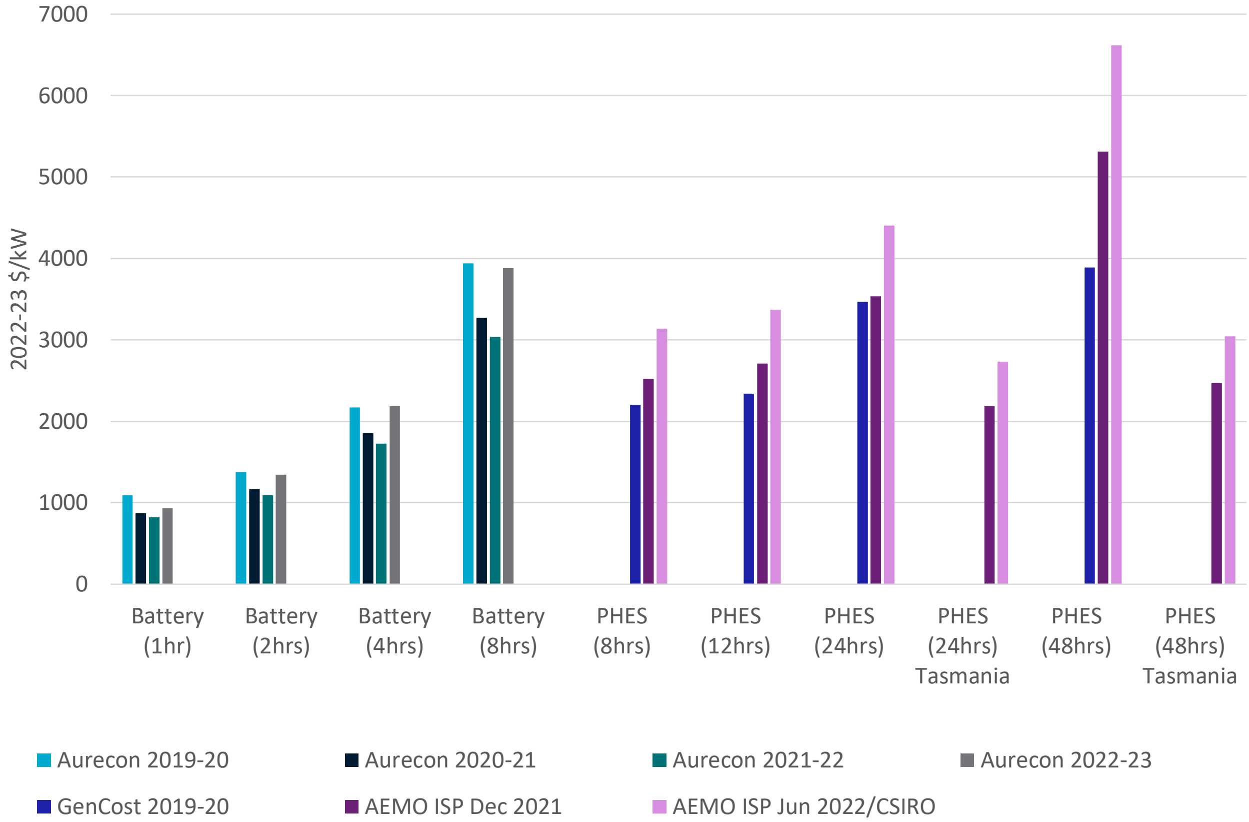


Figure 2-4 Capital costs of storage technologies in $/kW (total cost basis)

3 Scenario narratives and data assumptions

The scenarios were redesigned for GenCost 2021-22. For 2022-23 the scenario narratives have not changed but there have been some minor updates to data assumptions.

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 Outlook (IEA, 2021) scenario matching to the Stated Policies scenario, Sustainable Development Scenario respectively and Net Zero Emissions by 2050. IEA (2021) slightly de-emphasised the Sustainable Development Scenario and it was dropped in 2022, 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[10]). This represents mid- 2021 climate and renewable energy policy commitments with no extension beyond targets existing at that time[11]. 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

[10] 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.

[11] 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

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*.

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 3-1 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 3-7.

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 3-2, Table 3-3 and Table 3-4 showing the relationship between generation technologies and their components and the assumed learning rates under the central scenario. Learning is either on a global (G) basis, local (L) to the region, or no learning (-). 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 3-2 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	(Schmidt et al., 2017)
		L	10	5	
Electrolysis	Global NZE by 2050	G	18	9	
		L	18	9	
Electrolysis	Global NZE post 2050	G	10	5	
		L	10	5	
Ocean	Current policies	G	10	5	(IEA, 2021)
	Global NZE by 2050	G	20	10	
	Global NZE post 2050	G	14	7	
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.

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 (2022a) 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.

Table 3-3 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.

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 3-2 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 3-3. The remainder of learning rate assumptions, which do not vary by scenario are shown in Table 3-4.

Table 3-4 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)
Nuclear 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)

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. This assumption extrapolates past trends.

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.

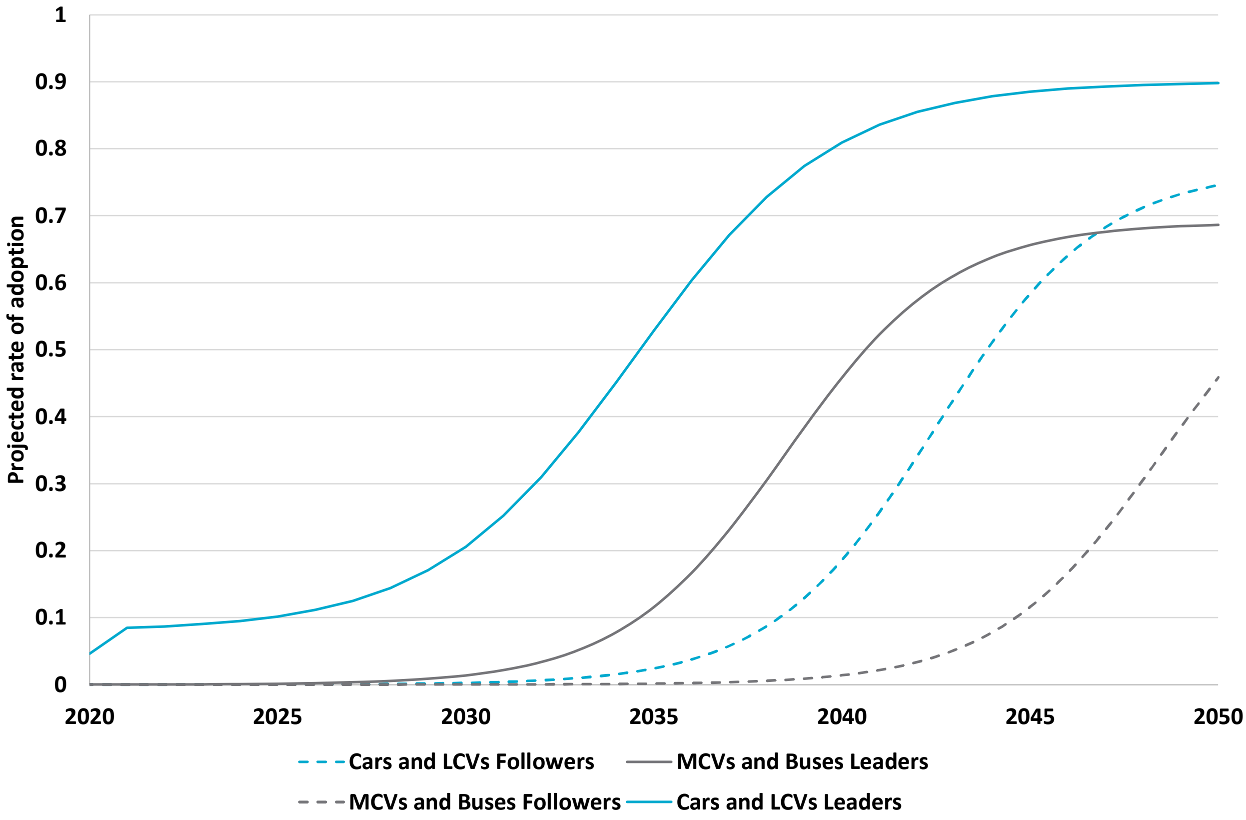


Figure 3-1 Projected EV sales share under the *Current policies* scenario

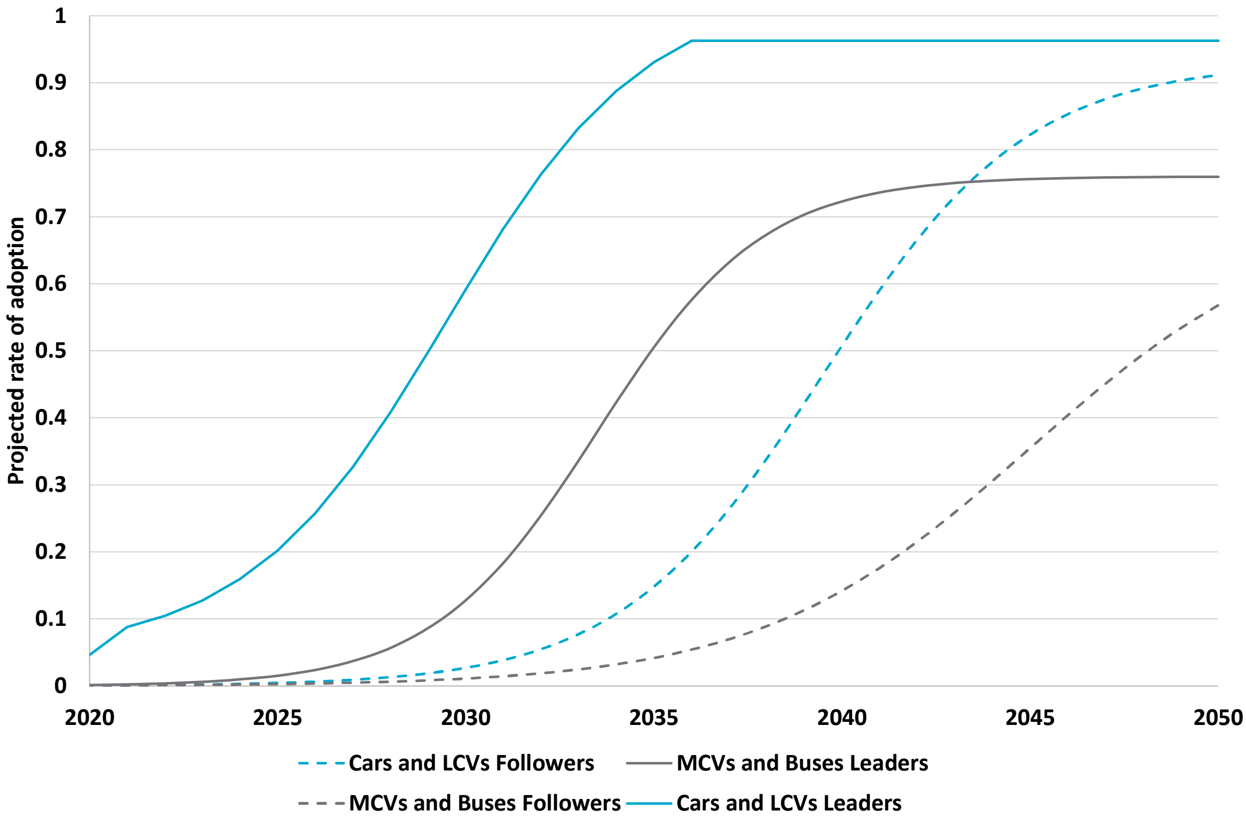


Figure 3-2 Projected EV adoption curve (vehicle sales share) under the *Global NZE by 2050* scenario

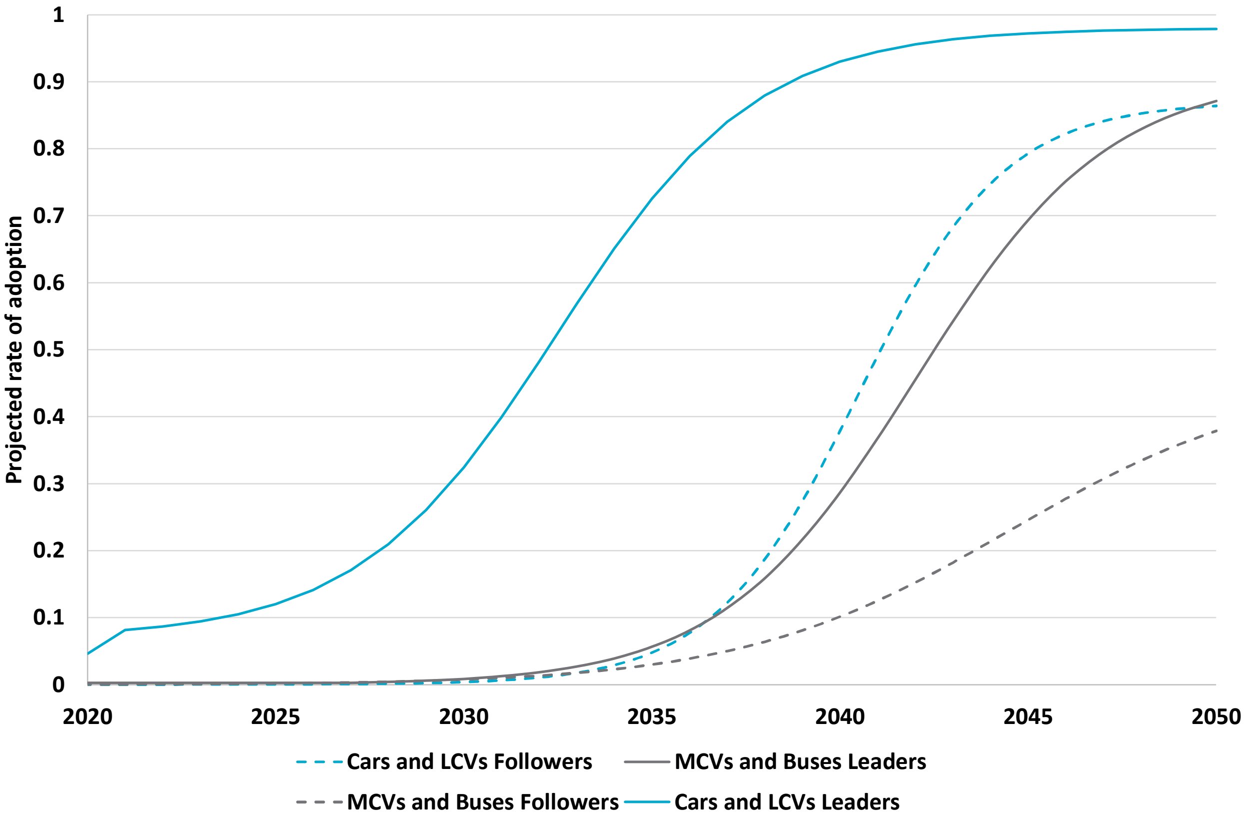


Figure 3-3 Projected EV sales share under the *Global NZE post 2050* scenario

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 3-5 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 3-6 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 3-6 Hydrogen demand assumptions by scenario in 2040

Scenario	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.

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. As such, the country policy commitments included are not completely up to date.

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 3-7) (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 black 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[12]. 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).

[12] 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 3-7 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 Incorporating short term inflationary pressures

Over the last two years the cost of a range of technologies including electricity generation, storage and hydrogen technologies has increased rapidly driven by two key factors: increased freight and raw materials costs. The most recent period where similar large electricity generation technology cost increases occurred was 2006 to 2009 with wind turbines and solar PV modules being most impacted. The cost drivers at that period of time were policies favouring renewable energy in Europe, which led to a large increase in demand for wind and solar. This coincided with a lack of supply due to insufficient manufacturing facilities of equipment and polysilicon in the case of PV and profiteering by wind turbine manufacturers (Hayward and Graham, 2011). Once supply caught up with demand the costs returned to those projected by learning-by-doing and economies of scale.

CSIRO has explored a number of resources to understand cost increases already embedded in technology costs and project how this current increase in costs will resolve over the next five years. We normally use our model GALLM to project all costs from the current year onwards. While GALLM takes into account price bubbles caused by excessive demand for a technology (as happened in 2006-2009) the drivers of the current situation are different and thus we have decided to take a different approach, at least for projecting costs over the next five years. It is not appropriate to project long term future costs directly from the top of a price bubble, otherwise all future costs will contain the current temporary market conditions. Therefore, the model has not been used for costs up to the year 2026. However, from the year 2027[13] onwards, the cost projections will be directly sourced from GALLM.

The first and primary source of 2022 costs is Aurecon (2022a). Aurecon (2022a) provides an update on the current costs of contracting the deployment of most of the technologies included in GenCost. The exceptions are some mature technologies such as coal and less commonly deployed and emerging technologies such as wave energy. Aurecon (2022a) costs for 2022 were not used directly for offshore wind, solar thermal, hydrogen and natural gas reciprocating engines. These are cases where inflationary effects had not been included or they were lower than the 2021 costs which is contrary to recent cost increases seen in all other technologies.

The 2022 costs for technologies not included in Aurecon (2022a) and both types of reciprocating engines, solar thermal and offshore wind have been calculated by multiplying the previous year's costs by a "basket of costs" factor to take into account the 2022 cost increases. To project the 2023 and 2024 costs the "basket of costs" calculation was extended out to those years and was

[13] We have chosen 2027 to align our assumptions with projections that suggest fossil fuel prices will return to normal by 2027, returning energy input costs to normal for most industrial supply chains. The projections were presented at the 26th October AEMO Forecasting Reference Group meeting.

applied to all technologies except for more commonly deployed renewable technologies where we were able to source more detailed information.

The approach used to determine this “basket of costs” factor is similar to that already taken for mature technologies (Appendix A 1.3) where we apply historical values of the CPI, imported equipment, domestic equipment and labour indices. However, for this approach we used projections of the CPI[14], continued the current trend in the labour index out to 2024 and estimated the domestic[15] and imported equipment indices based on materials and logistics cost projections (Mukherjee, 2022). These “basket of costs” factors have been calculated and applied to each technology on an annual basis, based on the share of local and imported equipment and installation costs.

For onshore wind, solar PV, batteries and electrolysers we were able to source projected costs to the year 2024 from S&P Global (Mukherjee 2022; Berg 2022; Jin & Zocco, 2022; Huntington 2022; Nikoleishvili & Klaesig, 2022; Davies & Nikoleishvili, 2022). However, these costs were not specifically designed for Australia but rather for the technologies on a global level. We thus used the Aurecon (2022a) costs as a starting point and applied the trend in costs from S&P Global to the Aurecon (2022a) 2022 cost.

For all technologies the 2025 and 2026 costs were based on an interpolation between the 2024 projected cost and the 2027 modelled results.

This common methodology to 2027 results in no variation in the projections by scenario until after 2027. We may consider building in some variation between scenarios in the short-term forecasts once we have initial feedback on the draft projections.

While we have used the trends in price indices of selected goods to inform our analysis of short-term changes in technology costs, all projections remain in real terms. That is, the projected price increases in the short term are in addition to the general level of inflation.

4.2 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.

[14] https://www.rba.gov.au/publications/smp/2022/may/forecasts.html

[15] https://www.aer.gov.au/system/files/AGN%20-%20Attachment%207.8A%20-%20BIS%20Oxford%20Input%20Cost%20Escalation%20Forecasts%20to%202025-26%20-%2013%20January%202021.pdf

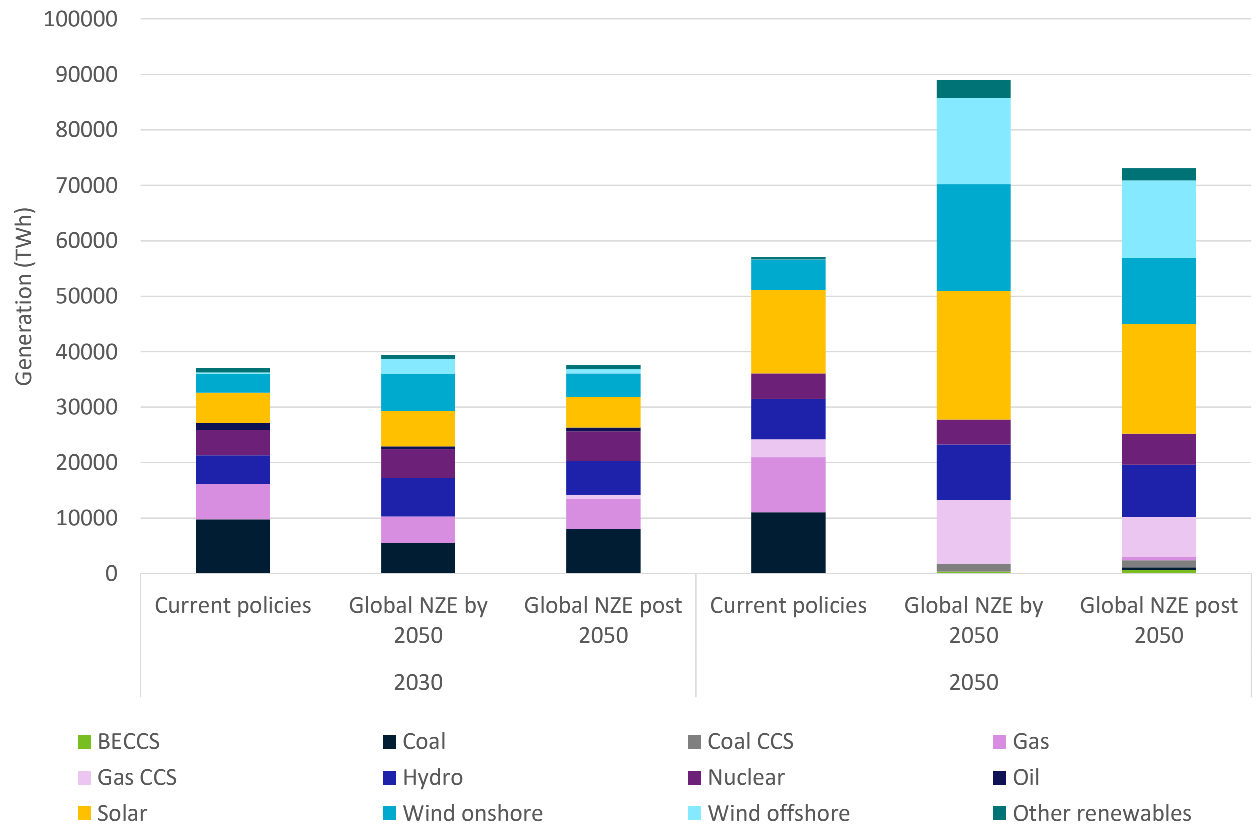


Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

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[16]. 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 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 in 2030. 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 37% 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 8% in *Global NZE post 2050*.

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. 99% of generation from fossil sources is with CCS accounting for 15% of generation by 2050. Offshore wind features strongly in this scenario at 17% of generation by 2050. Renewables other than

[16] 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.

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.

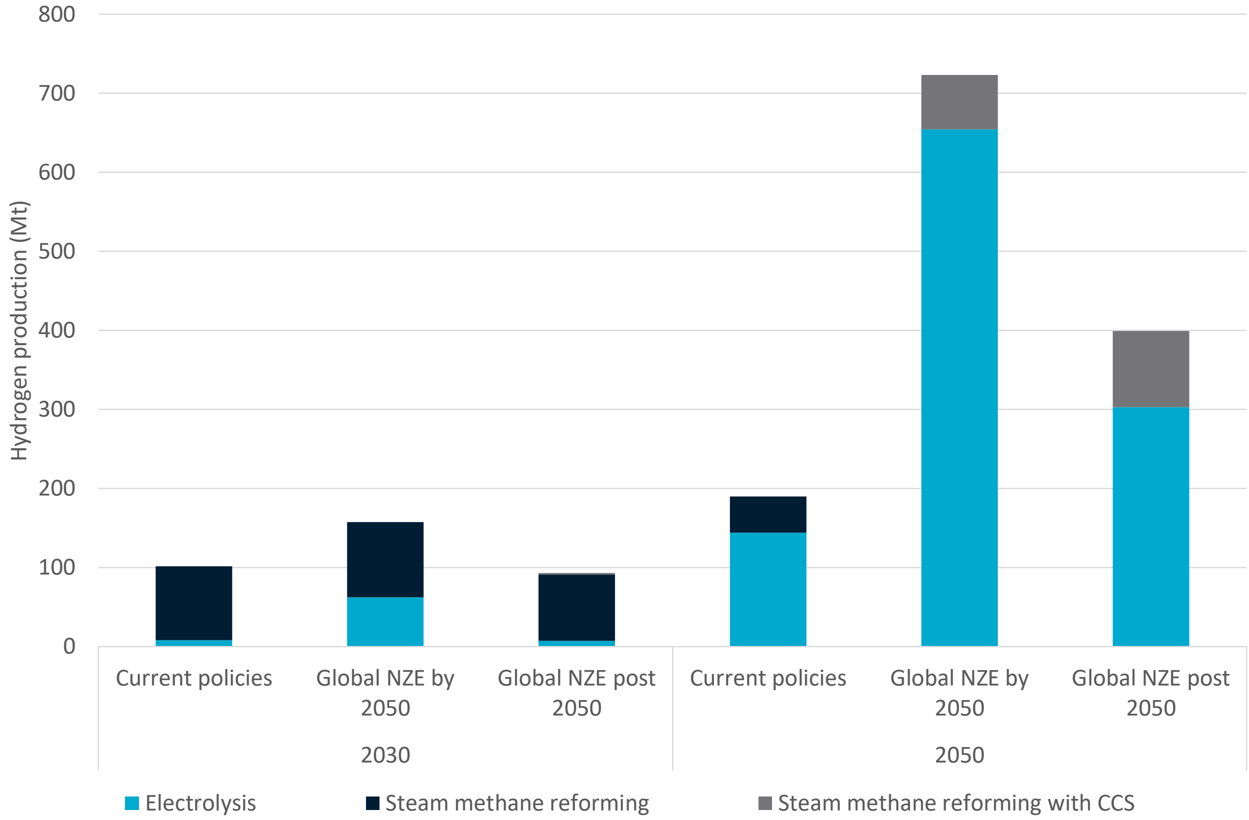


Figure 4-2 Global hydrogen production by technology and scenario, Mt

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2021-22 projections. For mature technologies, where the current costs have not changed and the assumed improvement rate after 2027 is very similar, their projection pathways often overlap. The assumed annual rate of cost reduction for mature technologies post-2027 is 0.35% (the same as the 2021-22 report). 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[17].

4.3.1 Black coal supercritical

The cost of black coal supercritical plant in 2022 has been assumed to increase and then return to its previous level by 2027 aligned with our approach for incorporating current inflationary pressures for mature technologies outlined at the beginning of this section. The assumed rate of improvement in costs for mature technologies over time is the same as in 2021-22 and as a result the long term projection has not changed.

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

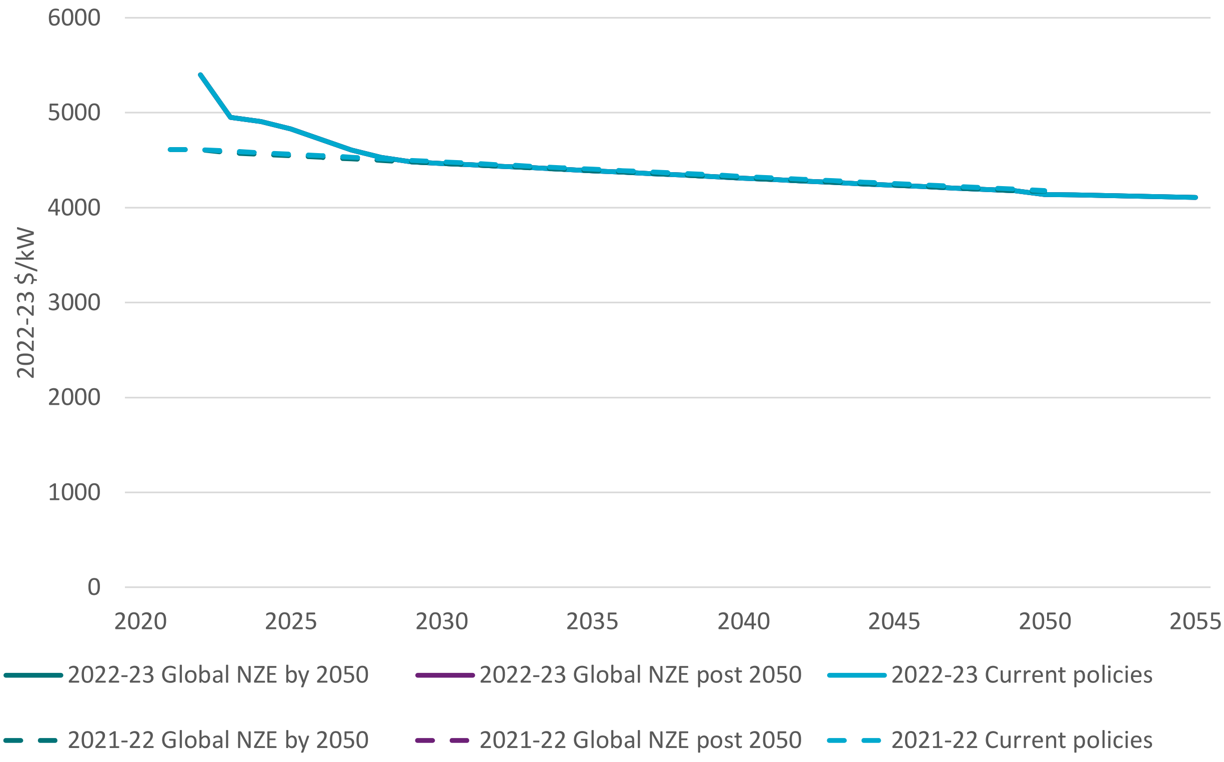


Figure 4-3 Projected capital costs for black coal supercritical by scenario compared to 2021-22 projections

4.3.2 Coal with CCS

The current cost of black coal with CCS from 2022 to 2027 has been updated in a similar manner as mature technologies, but with differences to take account of its unique set of inputs. Thereafter, the capital cost of the mature parts of the plant improve at the mature technology cost improvement rate. 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. Cost reductions up to 2027 are not technology related but rather represent the weakening of current inflationary pressures.

Current policies has no uptake of steam methane reforming with CCS in hydrogen production. Consequently, cost reduction from the late 2030s are mainly driven by the deployment of 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 CSS deployment in electricity generation is higher in *Global NZE by 2050.* The CCS deployment in hydrogen production is higher in *Global NZE post 2050*. Subsequently, those scenarios experience a similar amount of learning and cost reduction by 2050 but with differences in the timing of reductions.

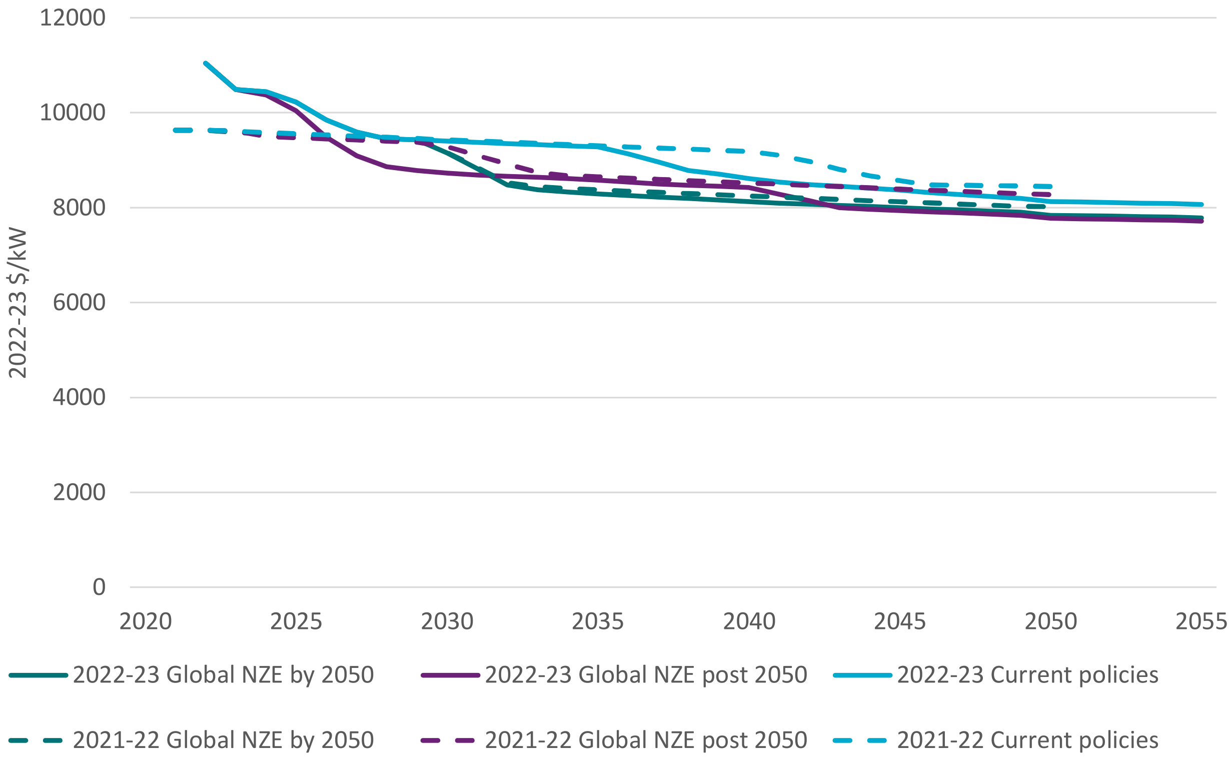


Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2021-22 projections

4.3.3 Gas combined cycle

Aurecon (2022a) have included an increase in gas combined cycle costs for 2022 and CSIRO has imposed an assumed return to previous costs levels by 2027. After 2027, because gas combined cycle is classed as a mature technology for projection purposes, 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.

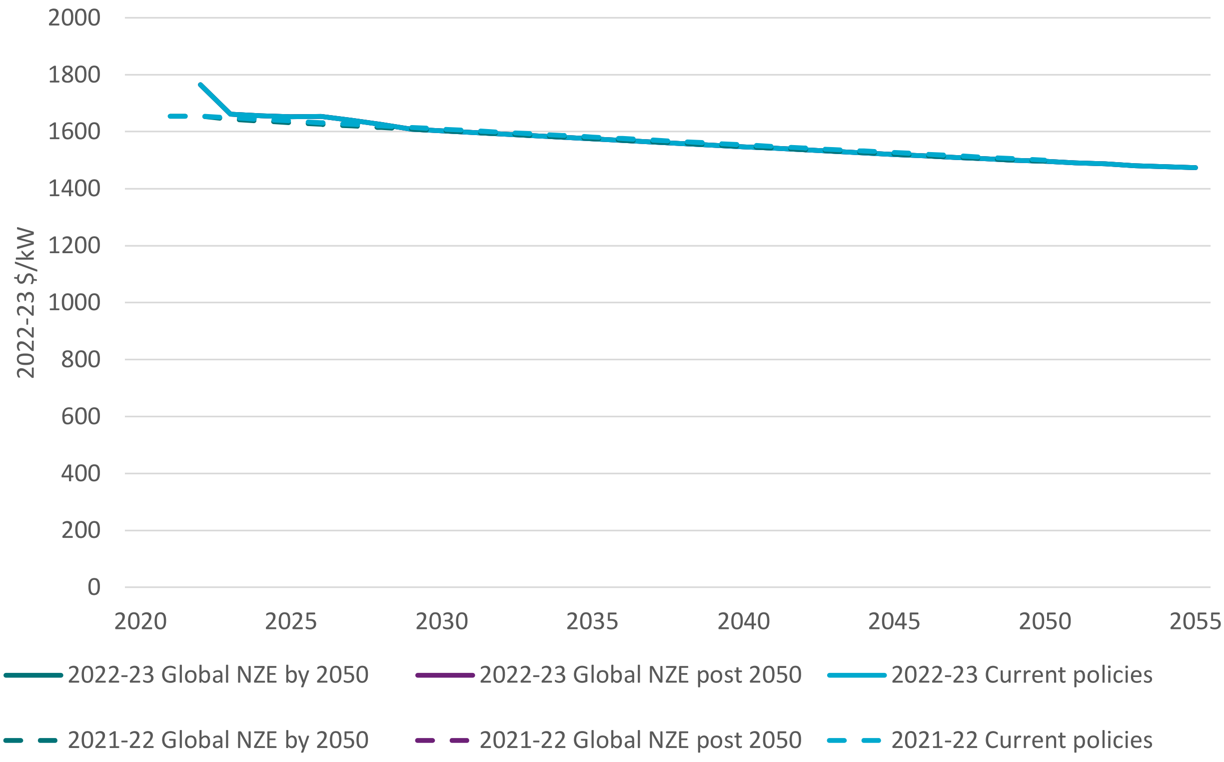


Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2021-22 projections

4.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2022-23 projections based on Aurecon (2022a). 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* and *Global NZE post 2050* have 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 those scenarios. Conversely, CCS is highest cost in *Current policies* where CCS deployment is lowest. CCS deployment for electricity generation purposes has occurred around five years earlier than in the 2021-22 projections under *Current policies* and is deployment is a little deeper overall in *Global NZE post 2050*.

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.

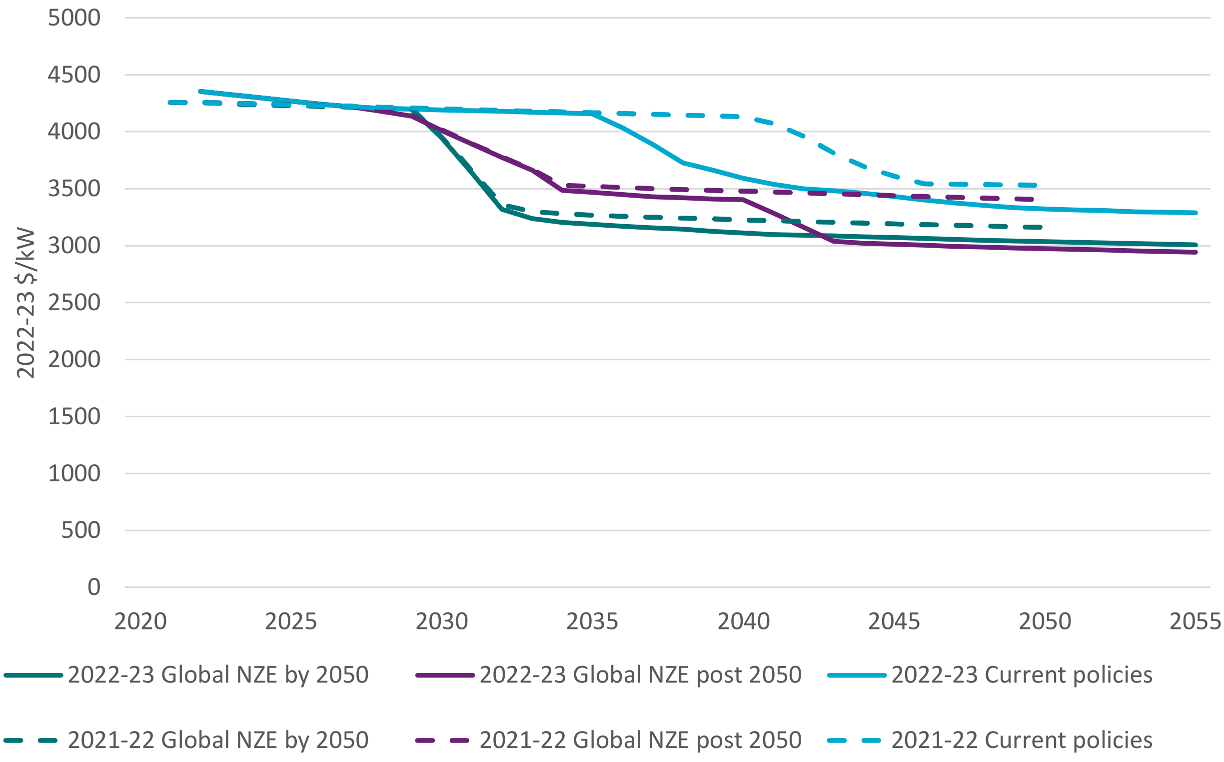


Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2021-22 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2021-22 and updated 2022-23 cost projections for small and large open cycle gas turbines. Aurecon (2022a) provides the details for the unit sizes and total plant capacity that defines the small and large sizes. Current costs are higher for both sizes based the updated data but are assumed to converge back to their previous projected levels by 2027. 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.

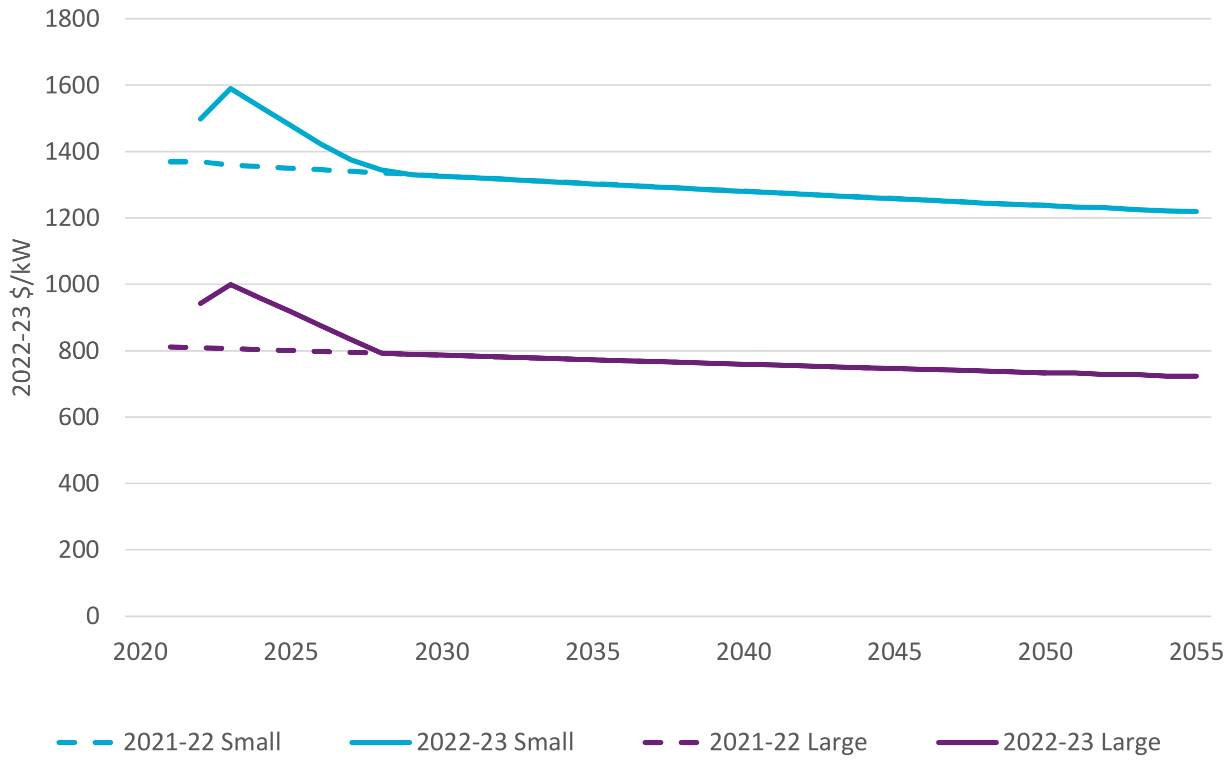


Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2021-22 projections

4.3.6 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. However, nuclear SMR is deployed globally in all scenarios. This is in contrast to the 2021-22 results where the technology was not taken up in the *Current policies* scenario. As *Current policies* evolves toward being a higher abatement scenario, with some countries increasing the ambition in their stated policies, this result demonstrates that nuclear SMR can play a greater role.

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 the learning rate assumptions which may be partly driven by modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. There is some variation in the timing and depth of reductions in the early 2030s. Capital costs are around $7300/kW to $8200/kW which is slightly lower than the low range of the 2021-22 projections (after adjusting for inflation).

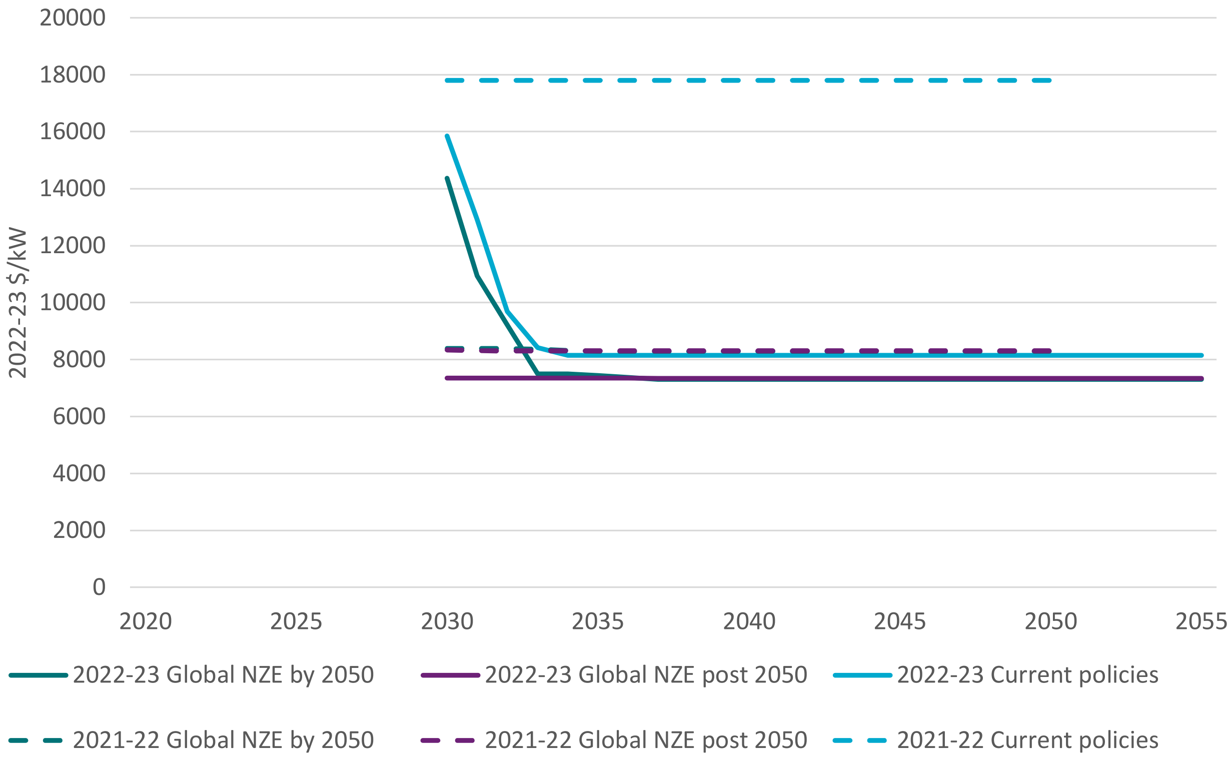


Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2021-22 projections

4.3.7 Solar thermal

Additional input from the solar thermal industry has indicated that the future preferred application of solar thermal has changed. Plans in Australia and elsewhere are not for standalone projects but rather for solar thermal to be integrated with other renewables such as solar PV and wind. In this case the role for solar thermal switches to provision of evening and nighttime generation. This role changes the configuration of the plant such as the ratio of the solar field to the power block. It is therefore not appropriate to compare costs to previous solar thermal project configurations which had a greater focus on daytime generation.

We apply the same adjustments for inflationary pressure to solar thermal as other technologies. After 2027 the projections diverge according to their scenario. The projected cost reductions are greater the stronger the global climate policy ambition in the scenarios.

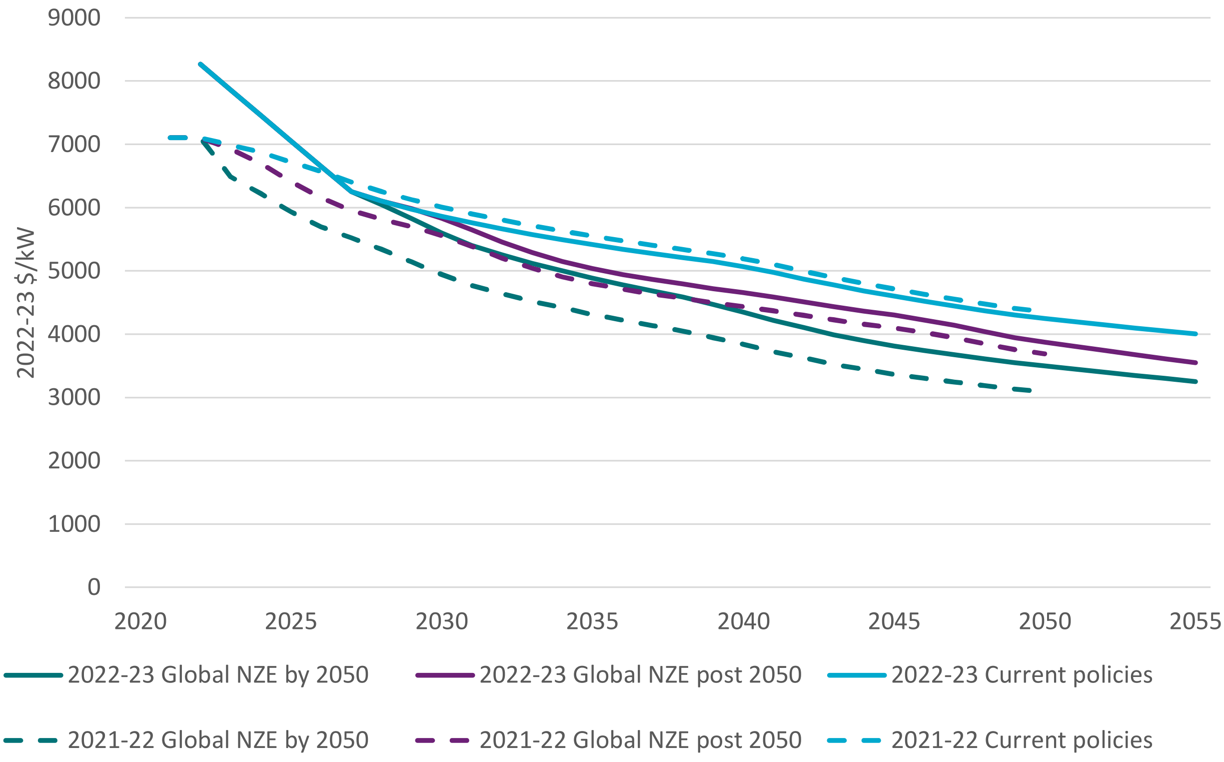


Figure 4-9 Projected capital costs for solar thermal with 15 hours storage compared to 2021-22 projections which were for 12 hours storage

4.3.8 Large scale solar PV

Large-scale solar PV costs have been revised upwards for 2022-23 based on Aurecon (2022a) and reflecting current global inflationary pressures. The broad applicability of solar PV technology to most regions of the world means that it is a major contributor to total electricity generation all global scenarios by 2050. By 2030, deployment of solar PV is proceeding faster in *Global NZE by 2050* but is similar in the remaining scenarios and this outcome is reflected in the cost reductions. For *Current policies* the deployment never catches up and it remains the lowest deployment highest cost scenario, whilst still achieving a greater than 50% cost reduction.

Deployment of large-scale solar PV in *Global NZE post 2050* accelerates in the 2040s such that costs converge by 2050 towards that achieved in the *Global NZE by 2050*, which is the scenario with the highest large-scale solar PV deployment level.

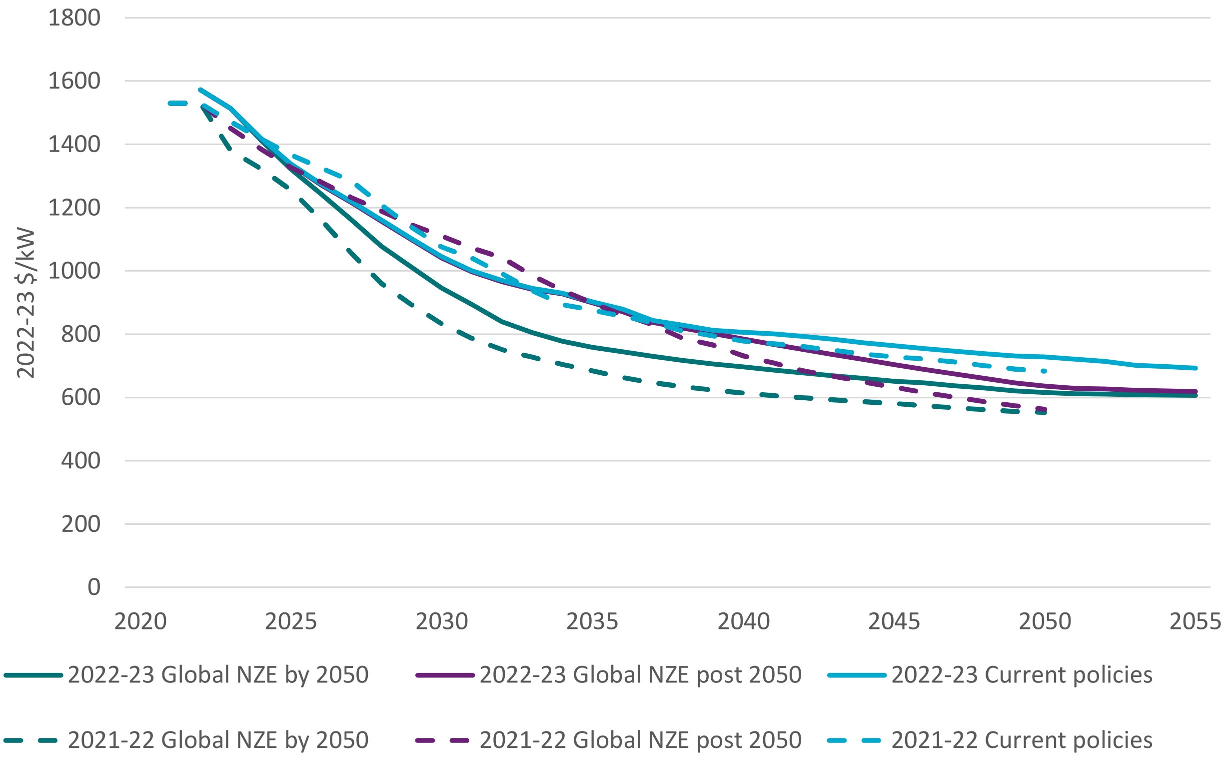


Figure 4-10 Projected capital costs for large scale solar PV by scenario compared to 2021-22 projections

4.3.9 Rooftop solar PV

The current costs for rooftop solar PV systems are higher and this increase has been aligned to that being experienced by large-scale solar PV. The price aligns to a 7kW system but it should be noted that rooftop solar PV is sold across a broad range of prices[18]. This 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.

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

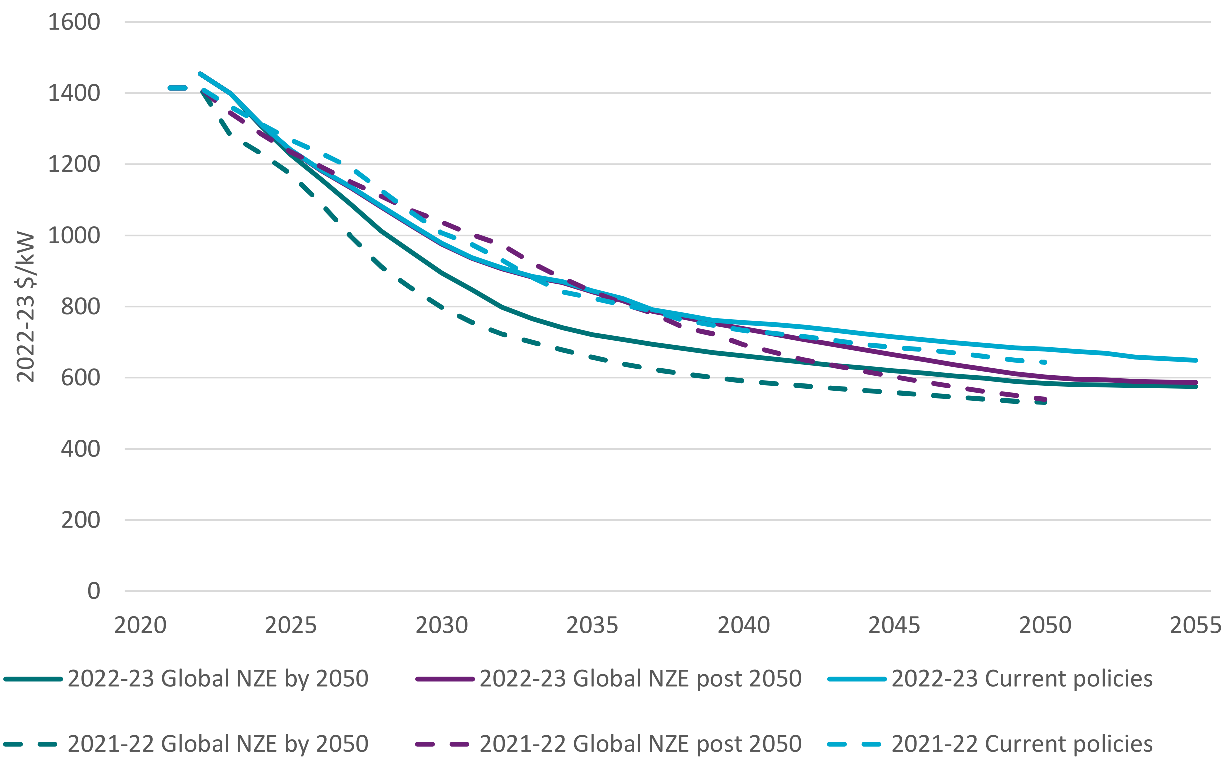


Figure 4-11 Projected capital costs for rooftop solar PV by scenario compared to 2021-22 projections

4.3.10 Onshore wind

The updated Aurecon (2022a) data indicates that onshore wind has experienced one of the highest increases in costs in 2022 (around a 35% increase). Our assumption is that this cost does not reflect normal conditions and that wind will return to its normal cost path by 2027. 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.

Besides these capital cost improvements, wind can achieve further cost reductions by improving its capacity factor over time (countering this may be a reduction in quality of sites as good quality sites are developed first). 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 (2022a) provides some projected changes in wind capacity factors to 2050.

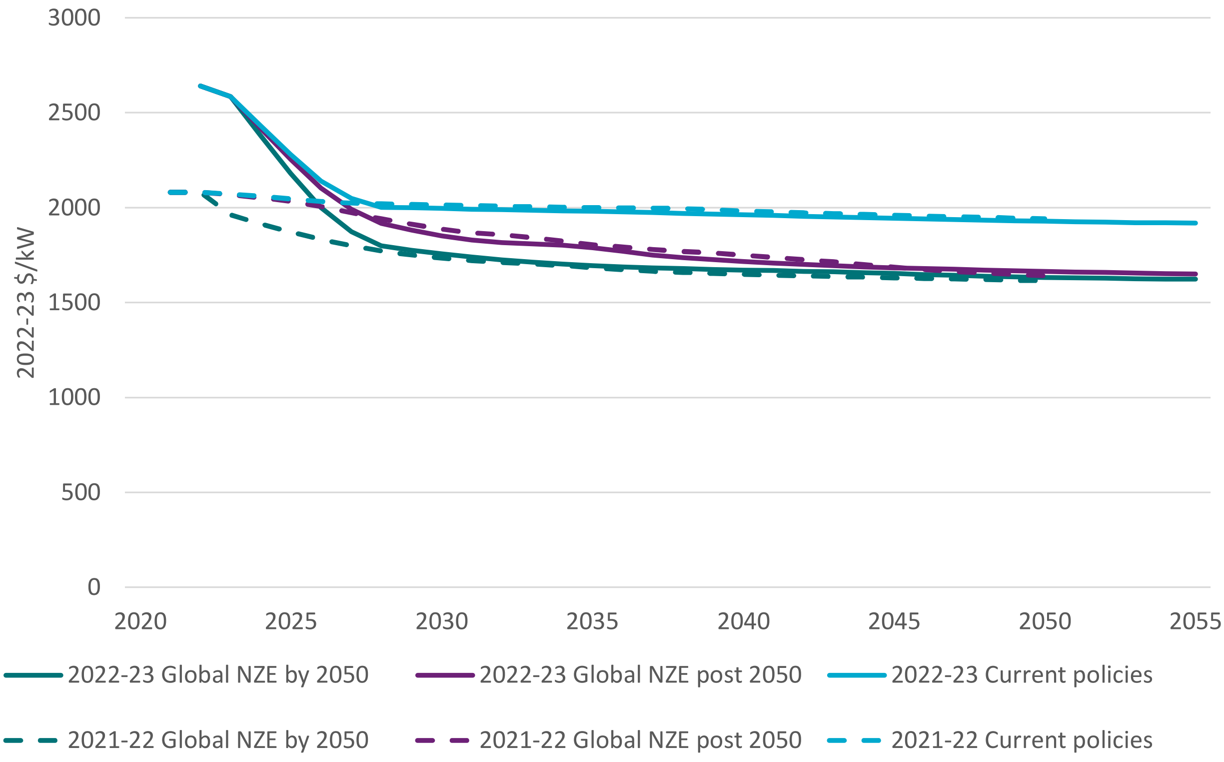


Figure 4-12 Projected capital costs for onshore wind by scenario compared to 2021-22 projections

4.3.11 Offshore wind

The higher 2022 starting points reflects the updated current cost data from Aurecon (2022a). From 2022 we've allowed *Global NZE by 2050* to resume cost reduction consistent with a stronger climate ambition as a result it reconnects with the previous 2021-22 trajectory. Under *Current Policies* and *Global NZE post 2030* scenarios cost reductions resume following the period of global inflationary pressures but in the long run are also consistent with 2021-22 projections reflecting similar levels of global deployment.

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.

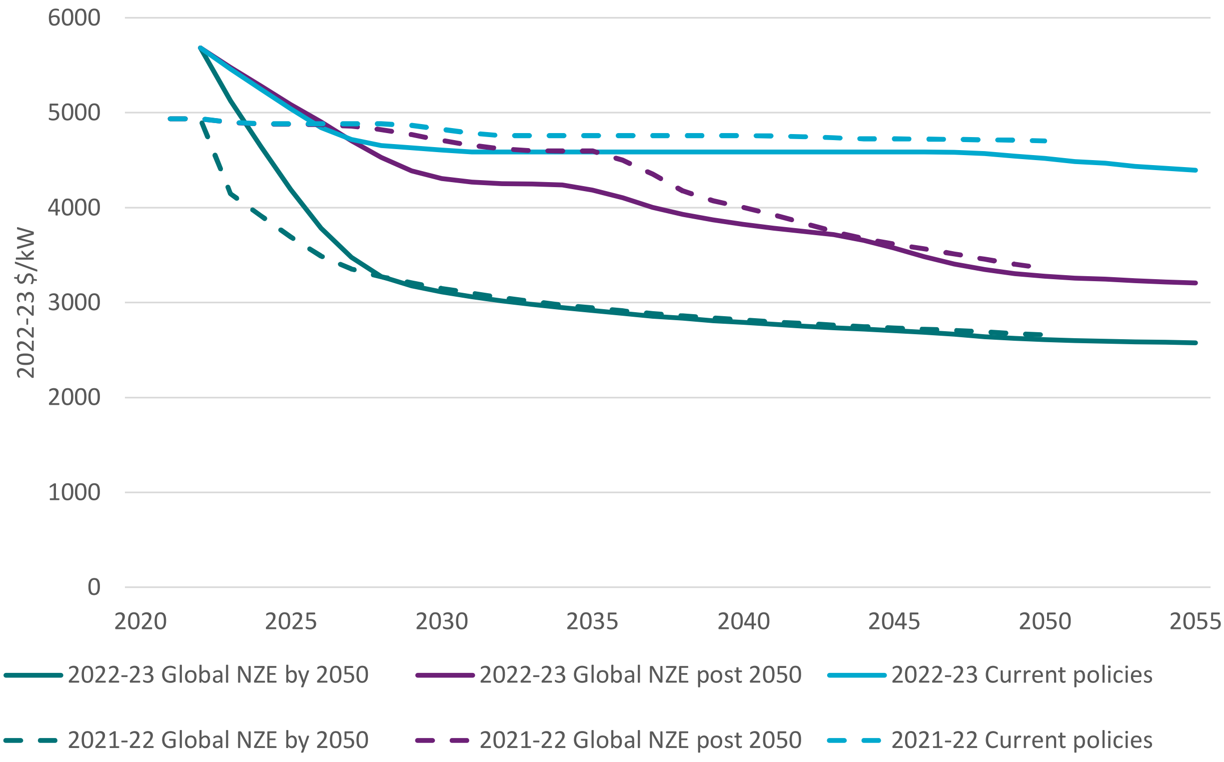


Figure 4-13 Projected capital costs for offshore wind by scenario compared to 2021-22 projections

4.3.12 Battery storage

The projections for batteries include a 20% increase in total costs and an underlying 37% increase in the battery component (excluding balance of plant). Consequently, batteries are one of the highest impacted technologies under the current global inflationary pressures. However, batteries have been able to sustain high rates of cost reduction over time and is it assumed that they are able to converge back to their underlying cost pathway by 2027.

The projections use different learning rates by scenario in order to reflect the uncertainty as to whether they will be able to continue to achieve historical cost reduction rates. 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).

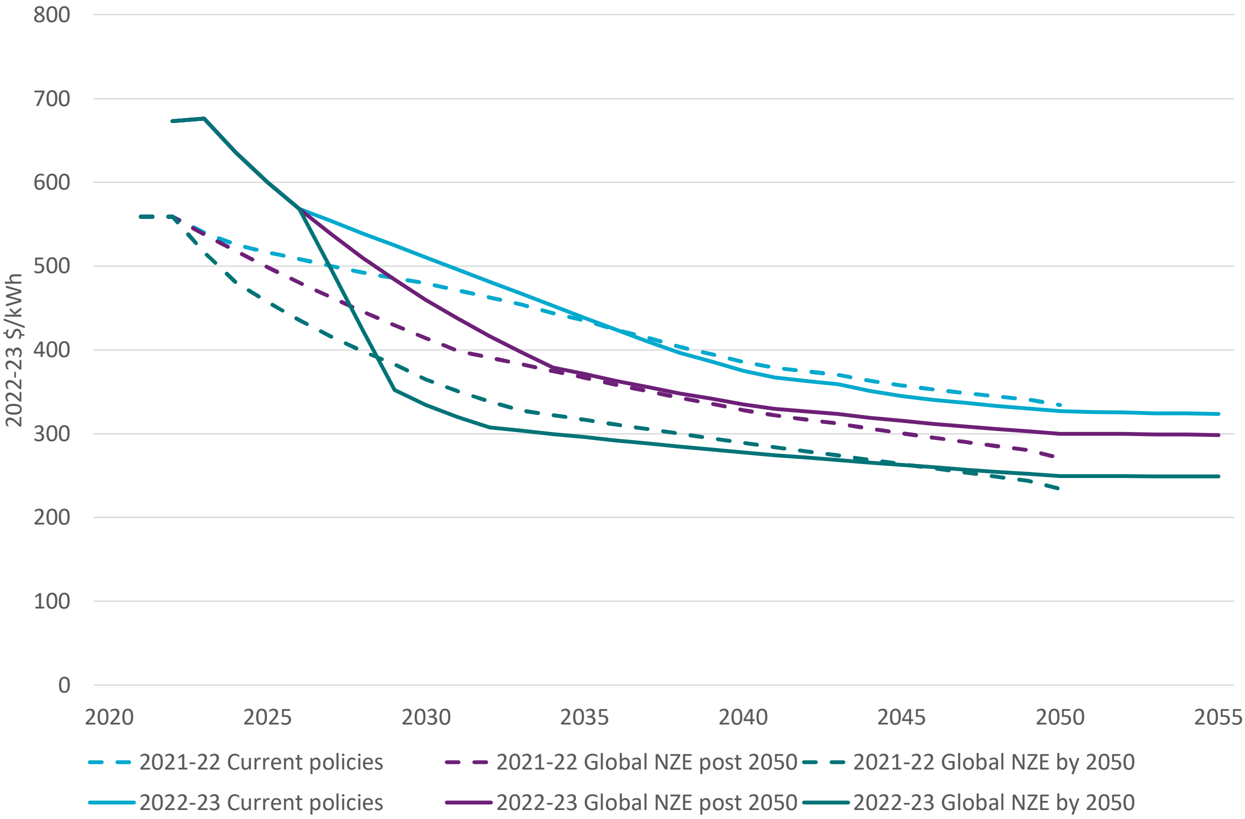


Figure 4-14 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

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 (2022a) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $16000 for a 5kW/10kWh system or $1600/kWh, including installation. This is more than twice the cost of large-scale battery projects.

4.3.13 Pumped hydro energy storage

Pumped hydro energy storage is assumed to be a mostly mature technology with only a small proportion of site piping/drilling costs having the potential to improve with deployment[19]. 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 is the 2020-21 and 2021-22 is the AEMO ISP input and assumptions

[19] 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 June 2022 respectively. These have been adjusted for ordinary inflation (being older estimates) and also for the current global inflationary pressures. 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.

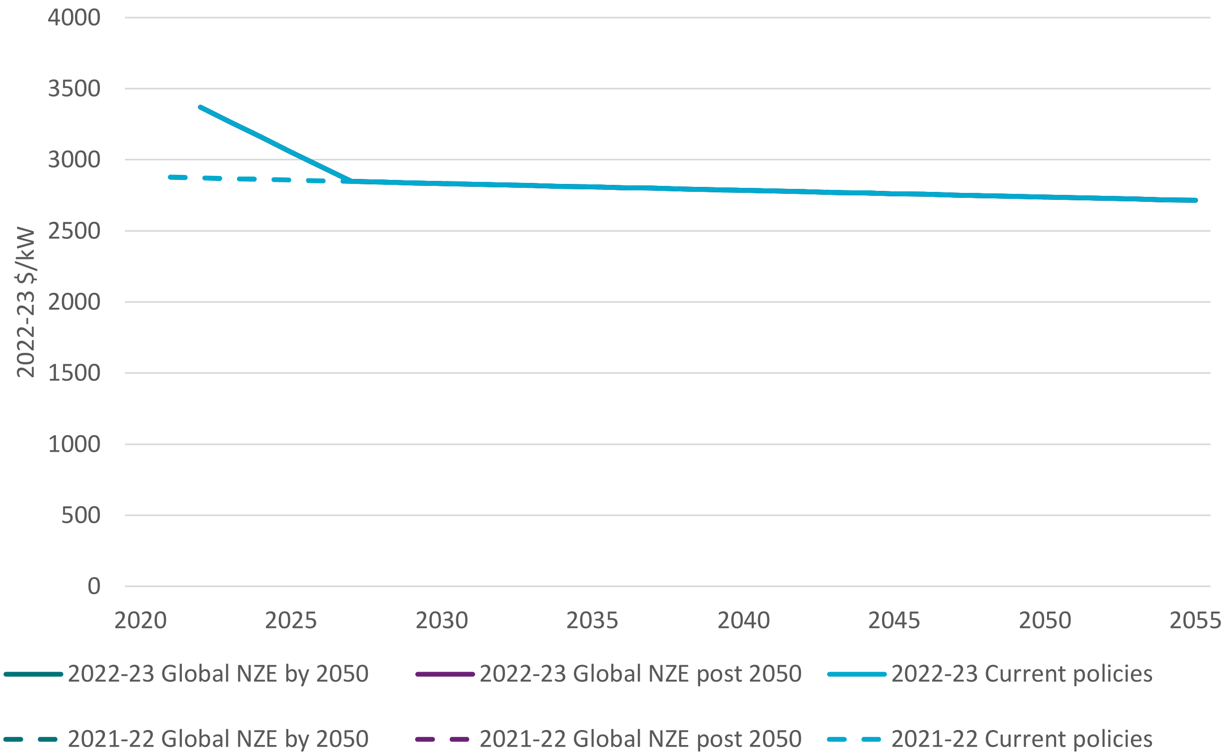


Figure 4-15 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

4.3.14 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. the increase in current costs and the downward trend to 2027 have been included using the same methodology for mature technologies. The scale of increase in 2022 fuel cell costs was sourced from Aurecon (2022a).

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 after 2027 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.

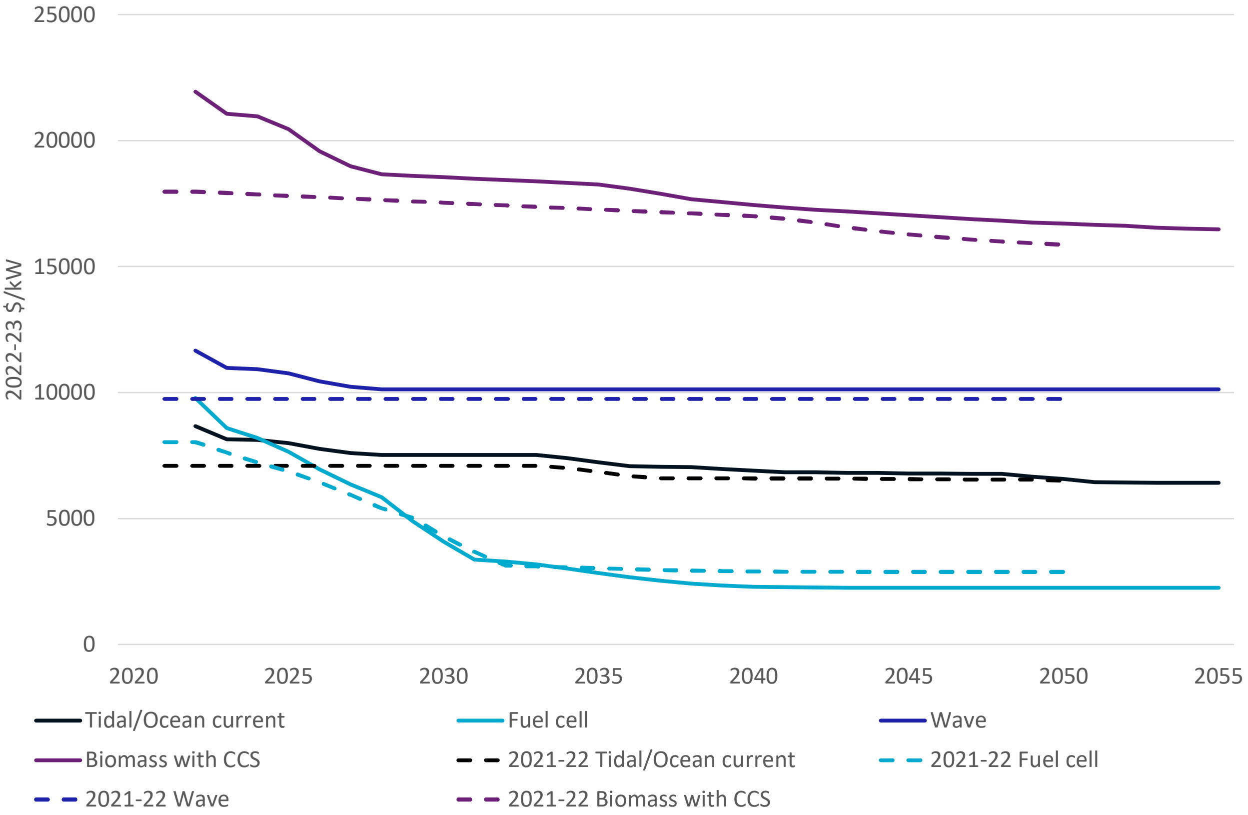


Figure 4-16 Projected technology capital costs under the *Current policies* scenario compared to 2021-22 projections

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 cells and wave energy are deployed although the early reduction in fuel cells reflects their use in the transport sector. Tidal/ocean current generation is not deployed to any significant level.

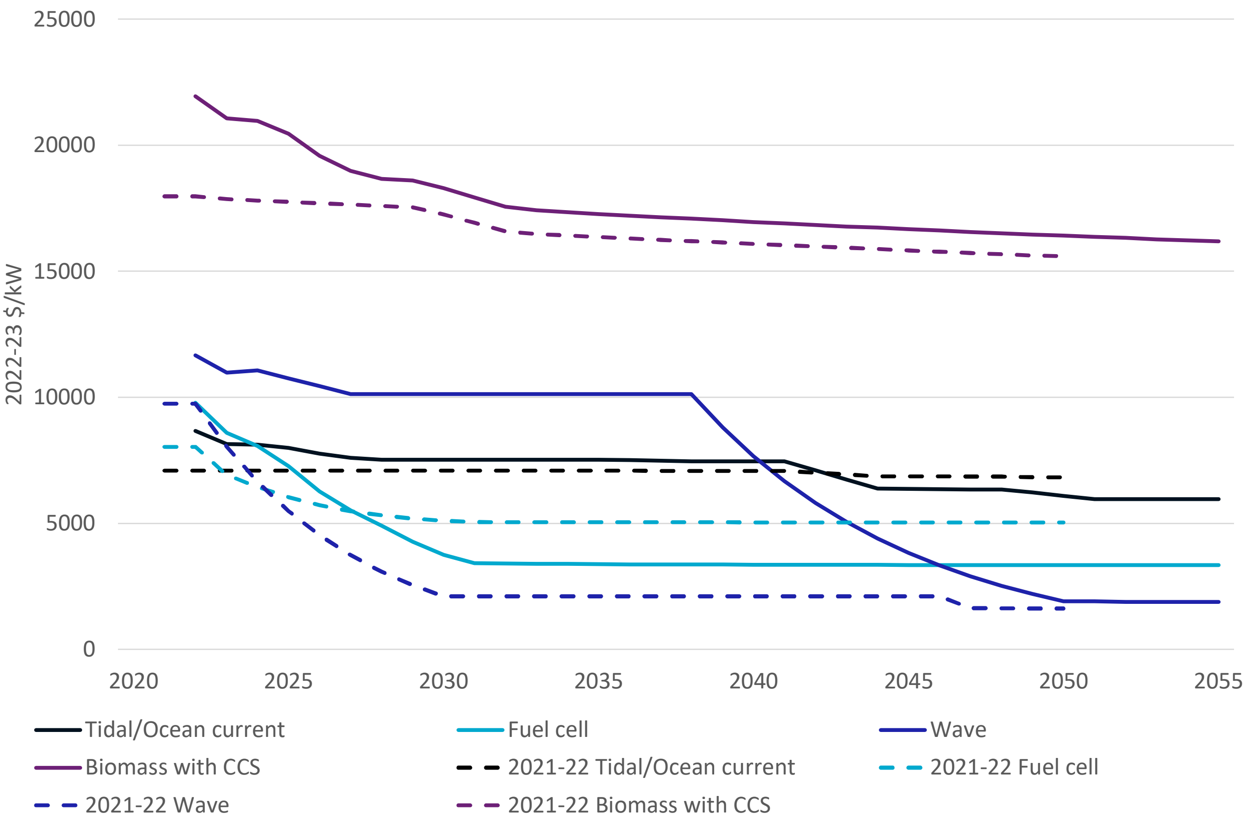


Figure 4-17 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2021-22 projections

Global NZE post 2050

Biomass with CCS is deployed at about half the level of *Global NZE by 2050*. However, the cost reductions achieved are similar to that scenario because the majority of cost reductions reflect co-learning from deployment of other types of CCS generation or use of CCS in other applications. Both scenarios have significant deployment of gas with CCS generation and steam methane reforming with CCS which brings down the cost of all CCS technologies sooner compared to *Current policies*. Similar to *Global NZE by 2050*, wave and fuel cell generation are preferred to tidal/current generation.

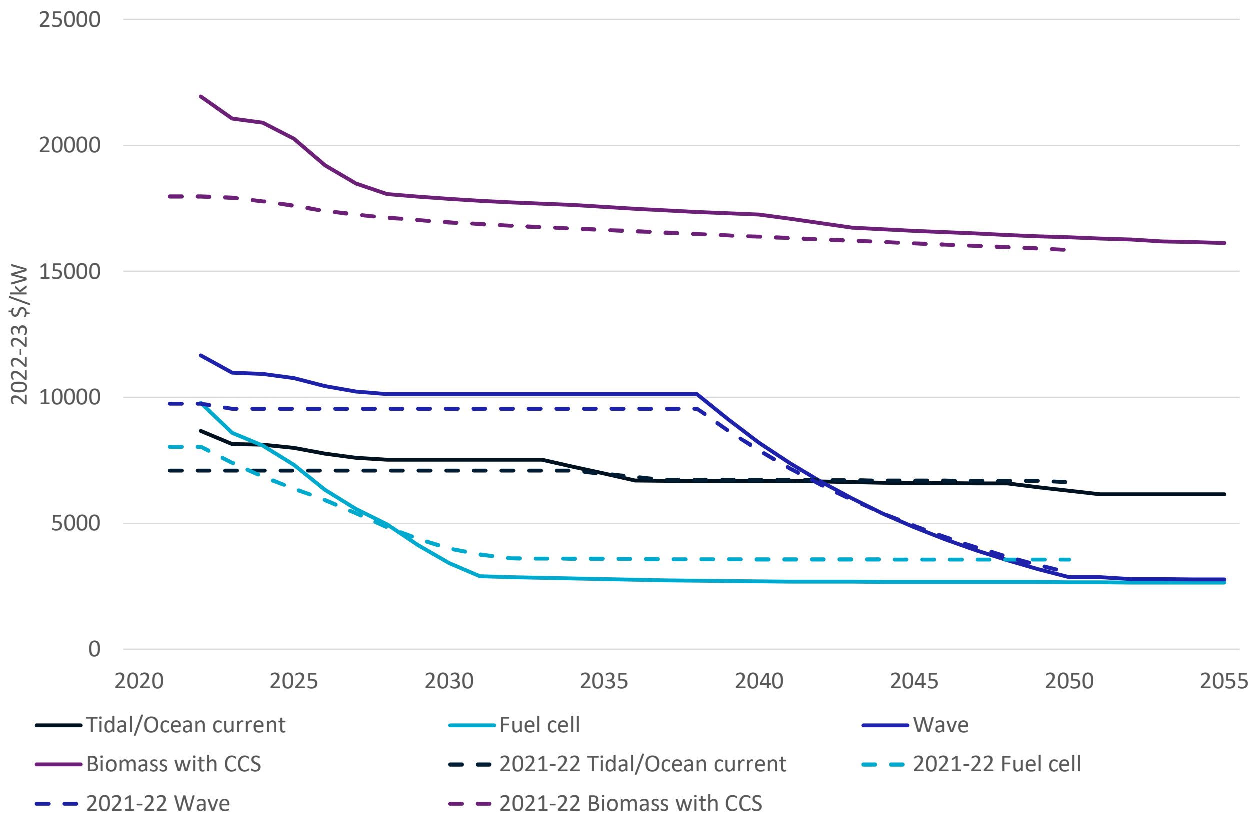


Figure 4-18 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2021-22 projections

4.4 Hydrogen electrolysers

Hydrogen electrolyser costs have increased in 2022 and the increase is sourced from Aurecon (2022a). Alkaline electrolysers are lower cost than proton-exchange membrane (PEM) electrolysers at present. 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. Electrolysers costs would otherwise remain similar to 2022 levels in 2023 and the subsequent cost reduction rate thereafter significantly slower without this scale effect.

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*.

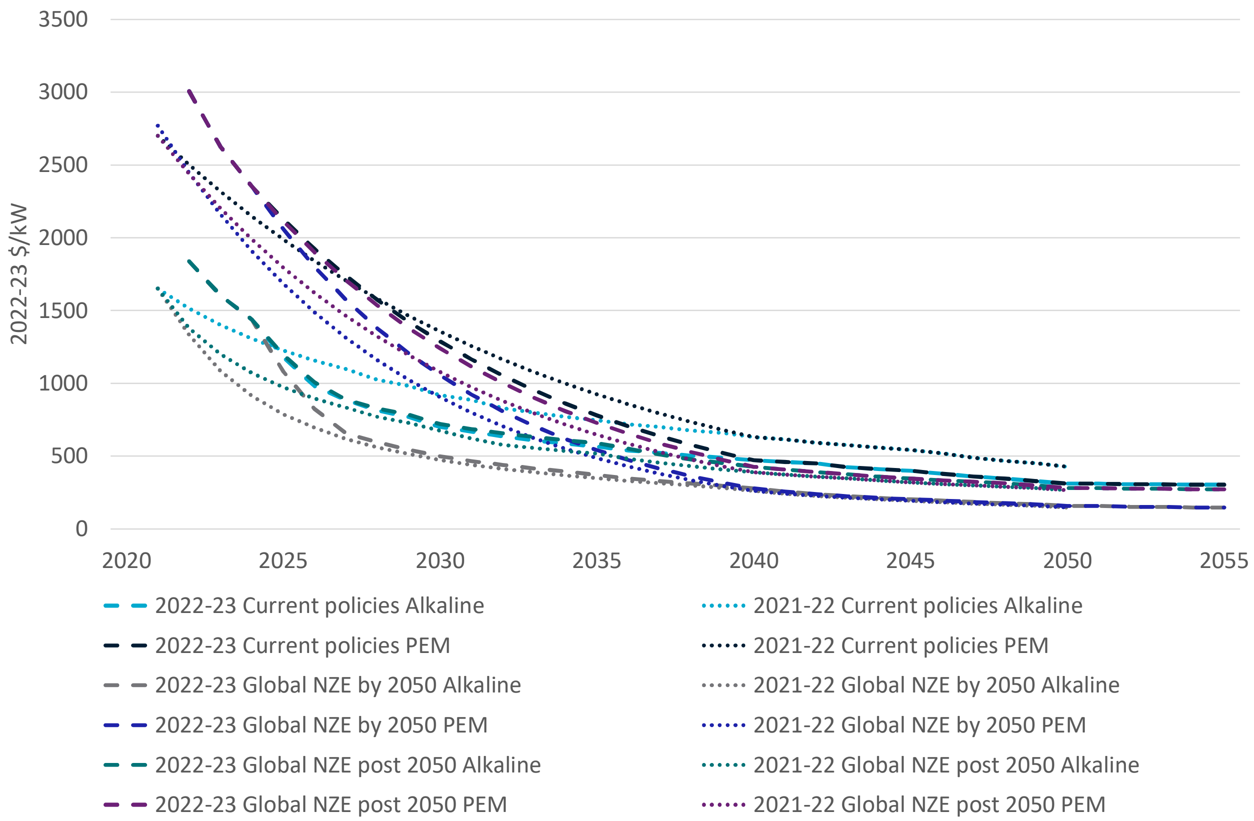


Figure 4-19 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2021-22

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[20]. 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).

[20] 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[21], 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 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[22].

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. A portion of 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 standard LCOE formula requires an assumption of a capacity factor. Our approach in this report is to provide a high and low assumption for the capacity factor (which we report in Appendix B) in order to create a range. Stakeholders have previously indicated they prefer a range rather than a single estimate of LCOE. However, it is important to note that these capacity factors are not used at all in the modelling of renewable integration costs. When modelling renewable integration costs, we use the variable renewable energy production traces published by AEMO for its Integrated System Plan. We incorporate the uncertainty in variable renewable production by modelling nine different weather years, 2011 to 2019, and the results represent the highest cost outcome from these alternate weather years.

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 54% in the NEM and 55% when WA is included. The share fluctuates a few percent depending on the nine weather years. The counterfactual VRE share reflects the impact of existing state renewable targets, planned state retirements of coal capacity in the case of WA and an already existing high VRE share in South Australia.

New South Wales, Queensland, Victoria and the SWIS are the main states that are impacted by the higher VRE shares imposed 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. The NEM is an interconnected system, so we are also interested in how those states

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[21] 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.

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

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[23]. 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. New South Wales (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.

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 50%. 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.

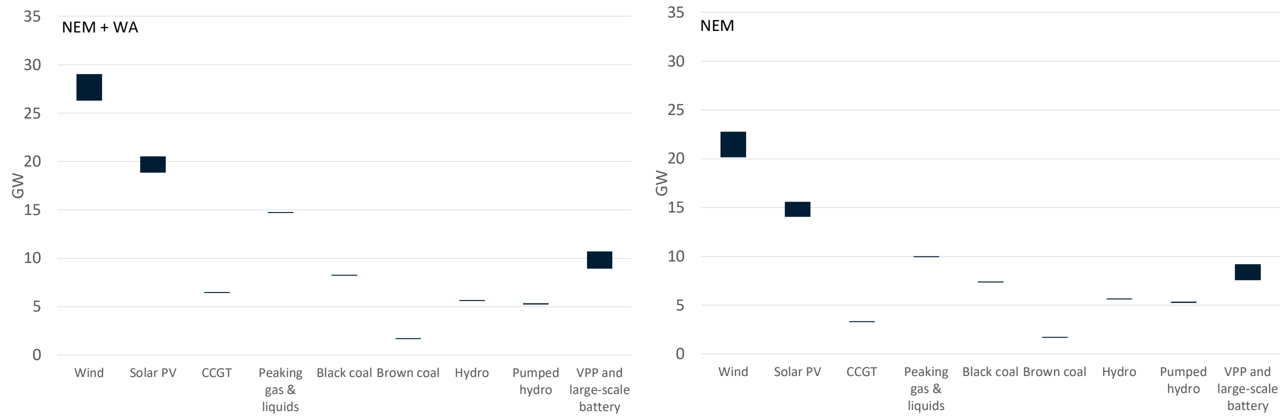


Figure 5-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia and NEM only

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 vary wind capacity by up to 2.7GW, solar PV capacity by 1.7GW and large-scale batteries (VPP capacity is fixed) by 1.8GW. The capacities shown have been compared with the AEMO ISP 2030 capacity projections. The NEM coal retirements to 2030 are aligned with Step Change (June 2022 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[24]. The NEM and WA total variable renewable shares are 54% and 61% on average across the weather years. The announced closure of the Muja and Collie coal generators by 2029 and 2027 respectively has increased the BAU variable renewable share in WA.

[23] 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.

[24] 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

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. Relative to the 2021-22 analysis, the NEM has a more even expenditure on storage and other transmission. Other transmission represents expenditure to strengthen the links between existing transmission zones (rather than connecting new renewable energy zones). Storage and transmission are somewhat in competition because they both help to manage variable renewable generation. Storage can shift variable renewable generation to a different time. Transmission supports access to a greater diversity of variable renewable generation by accessing resources in other regions which can help smooth supply. As transmission costs are updated, they have tended to increase in cost and this has likely led to a reduced reliance on transmission to balance supply in the modelling.

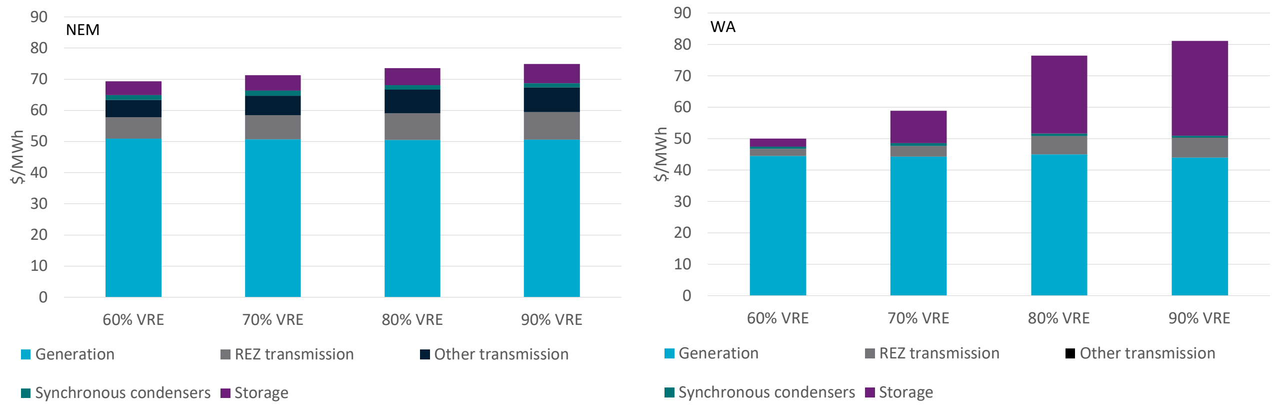


Figure 5-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in NEM and WA in 2030

REZ expansion costs appear to be required at similar levels for each additional 10% increase in VRE share and in each state. Other transmission costs have a rising trend in the NEM. The highest other transmission expenditure is 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. Queensland has recently announced some major pumped hydro projects to be completed by 2035[25], which is after the analysis period here.

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 $5 to $6/MWh with costs accelerating with VRE share. Storage adds $8 to $12/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 $25/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 flexible technology in 2030 is gas generation but only if it could be financed at a rate that does not include climate policy risk. Of the low emissions flexible technologies, gas with carbon capture and storage is 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.

[25] https://media.epw.qld.gov.au/files/Queensland_Energy_and_Jobs_Plan.pdf

5.1.4 Flexible technologies

Nuclear SMR, black coal, brown coal and gas-based generation technologies fall into the category of technologies that are designed to deliver energy for the majority (60% to 80%) of the year. They are the next most competitive generation technologies after variable renewables (with or without integration costs). The large reduction in fossil fuel generation costs between 2022 and the remaining years is not as a result of technological improvement. It represents a reduction in fuel prices from their current historical highs.

Of the fossil fuel technologies, it difficult to say which 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[26]. 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.

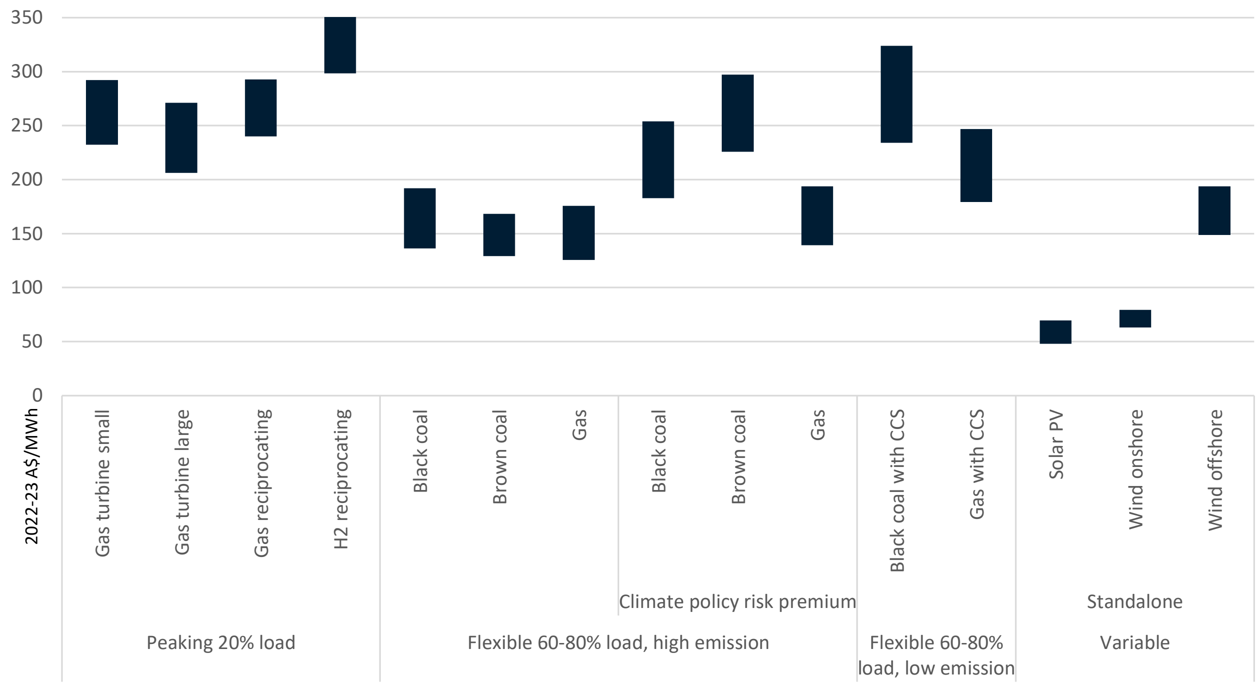


Figure 5-3 Calculated LCOE by technology and category for 2022

We do not include a risk premium for low emission flexible technologies. 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 capacity to bring down

[26] 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.

costs available to Australia. Lowest cost gas with CCS is subject to accessing gas supply at the lower end of the range assumed (see Appendix B for assumptions).

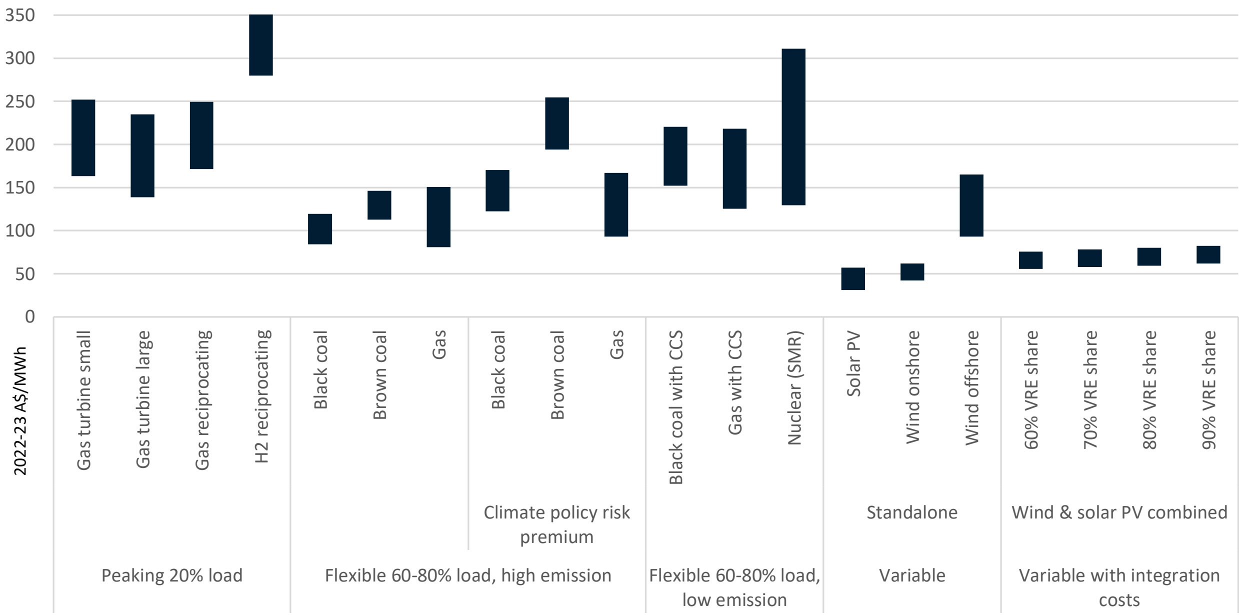


Figure 5-4 Calculated LCOE by technology and category for 2030

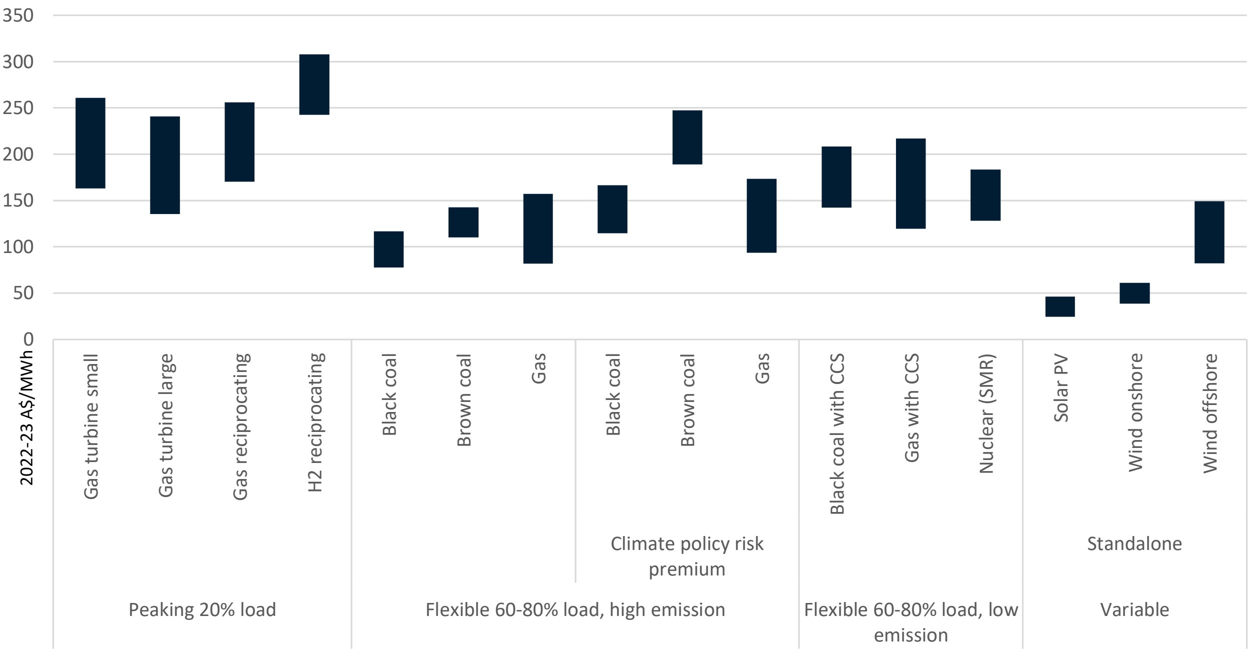


Figure 5-5 Calculated LCOE by technology and category for 2040

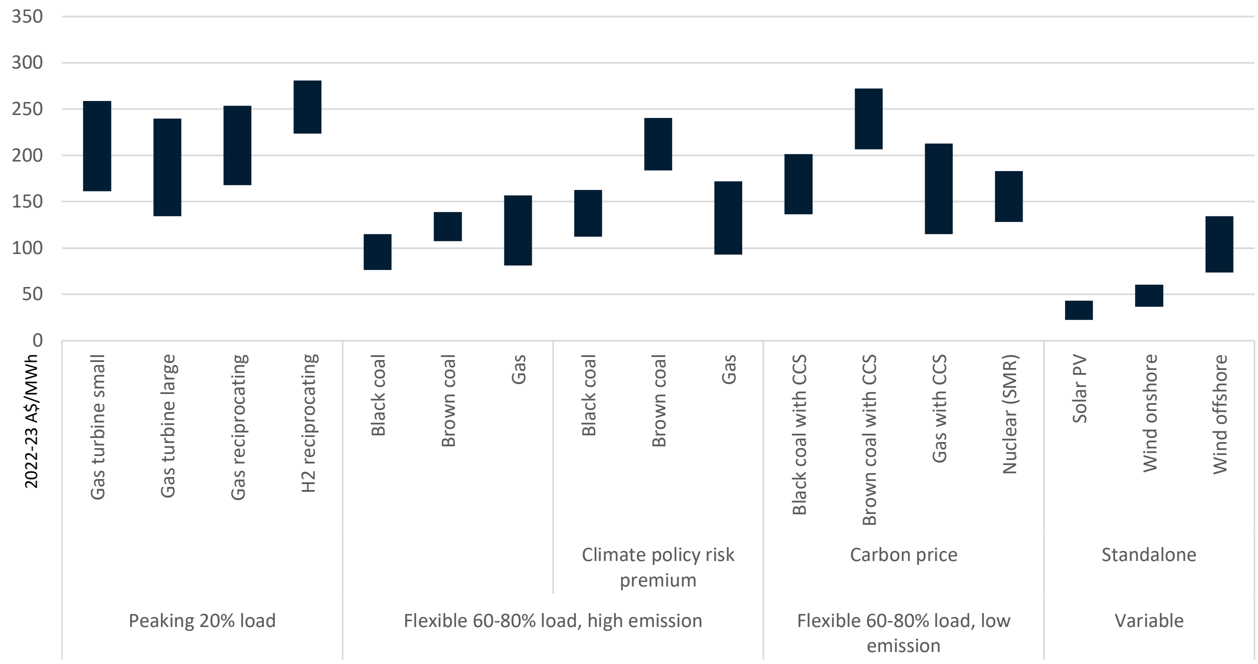


Figure 5-6 Calculated LCOE by technology and category for 2050

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 their actual generation over the year expressed as a percentage of their potential generation as defined by their rated capacity, is low (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 the 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 day, solar PV generation will have been high earlier in the day 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 0.26kW to 0.40kW storage capacity for each kW of variable renewable generation installed[27]. 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[28] is substantially lower than maximum demand and can mostly be met by non-storage technologies (although in this example renewable generation is not zero and can still contribute)
- Existing and new flexible capacity is slightly lower than maximum demand. This indicates that there is some variable renewable generation available at peak demand events in at least one state of the NEM (mostly likely wind generation if the peak occurs outside of daylight hours such as in the evening or early morning).
- 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.

[27] This is higher than the ratio calculated in GenCost 2021-22. However, as discussed in Section 5.11, this likely reflects the updated modelling selecting a higher ratio of storage to avoid higher transmission costs since these two resource types are partially substitutable.

[28] Calculated as sum of coincident NEM state demand.

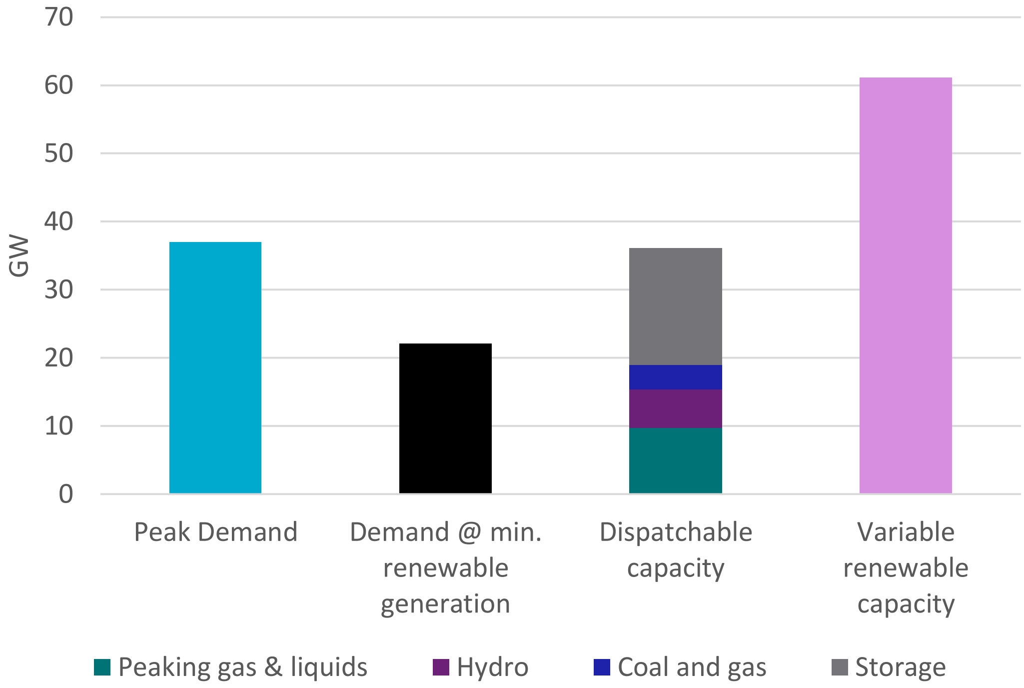


Figure 5-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

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:

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

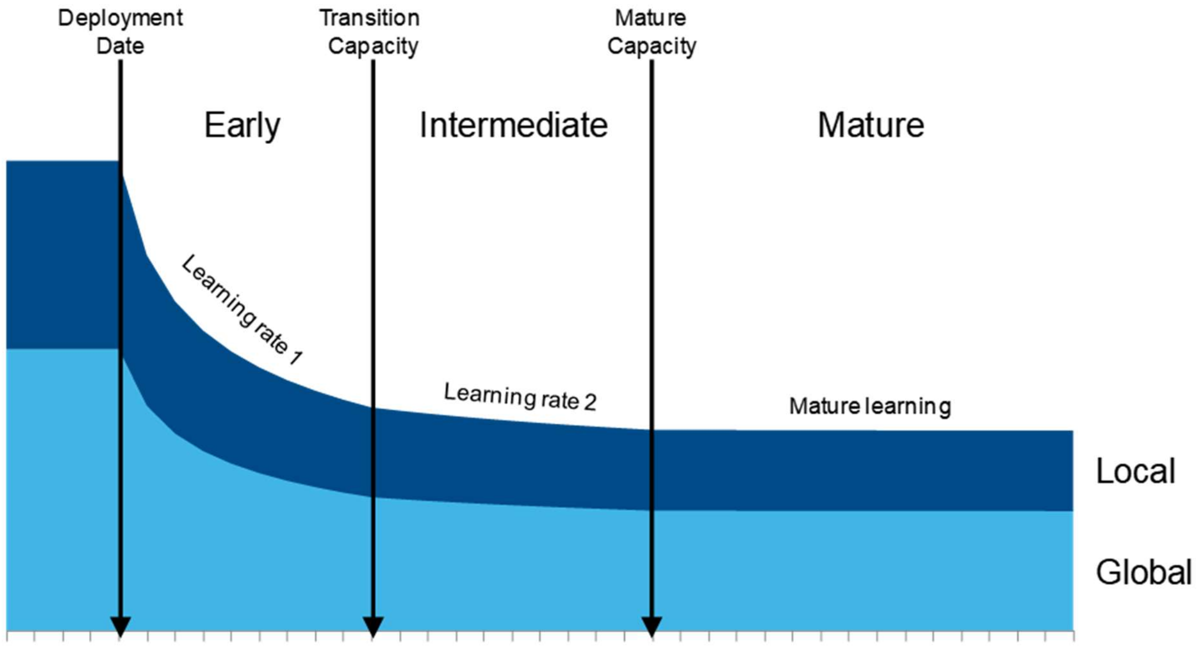
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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% (Schrattenholzer and McDonald, 2001). 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 2022 is mostly sourced from Aurecon (2022a) and is aligned to the middle of that calendar year or the beginning of the 2022-23 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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	8265	2642	5682	11662	-	8663	9787	2385
2023	4951	10486	7725	1661	1590	1000	4325	1755	2136	8646	21073	1514	1400	7862	2586	5460	10973	-	8152	8591	2346
2024	4908	10442	7699	1656	1534	959	4297	1727	2096	8562	20963	1419	1313	7459	2430	5248	10933	-	8122	8202	2204
2025	4830	10228	7570	1653	1478	917	4269	1717	2074	8282	20460	1339	1241	7056	2281	5042	10754	-	7988	7651	2078
2026	4719	9848	7341	1654	1423	875	4241	1726	2070	7814	19577	1274	1184	6654	2140	4845	10438	-	7754	6959	1977
2027	4608	9590	7131	1641	1376	834	4220	1718	2065	7512	18982	1219	1136	6251	2048	4715	10231	-	7600	6359	1893
2028	4529	9451	6991	1626	1345	792	4206	1705	2059	7365	18662	1161	1083	6105	2002	4652	10129	-	7524	5845	1815
2029	4481	9426	6916	1608	1331	790	4199	1687	2052	7365	18605	1102	1030	5977	1999	4630	10129	-	7524	4895	1736
2030	4465	9401	6892	1603	1326	787	4192	1681	2045	7365	18547	1045	978	5862	1996	4608	10129	15853	7524	4075	1659
2031	4449	9376	6868	1597	1322	784	4185	1675	2038	7365	18490	1000	938	5758	1993	4586	10129	12907	7524	3377	1593
2032	4434	9351	6843	1592	1317	781	4178	1669	2030	7365	18433	970	909	5663	1990	4586	10129	9691	7524	3289	1539
2033	4418	9326	6820	1586	1312	779	4171	1663	2023	7365	18377	944	885	5575	1987	4586	10129	8418	7524	3178	1489
2034	4403	9301	6796	1580	1308	776	4164	1657	2016	7365	18320	930	870	5493	1984	4586	10129	8147	7392	3014	1449
2035	4388	9276	6772	1575	1303	773	4157	1652	2009	7365	18264	902	844	5416	1981	4586	10129	8147	7235	2840	1398
2036	4372	9132	6748	1569	1299	770	4032	1646	2002	7365	18087	878	823	5344	1978	4586	10129	8147	7078	2662	1350
2037	4357	8968	6725	1564	1294	768	3889	1640	1995	7365	17892	844	791	5275	1974	4586	10129	8147	7045	2532	1295
2038	4342	8786	6701	1558	1289	765	3726	1634	1988	7365	17677	828	777	5209	1970	4586	10129	8147	7038	2414	1258
2039	4326	8703	6678	1553	1285	762	3662	1629	1981	7365	17563	812	762	5147	1966	4586	10129	8147	6964	2340	1223
2040	4311	8614	6654	1548	1280	760	3591	1623	1974	7365	17443	806	756	5069	1962	4586	10129	8147	6898	2290	1201
2041	4296	8541	6631	1542	1276	757	3537	1617	1967	7365	17339	801	750	4978	1958	4586	10129	8147	6833	2268	1183
2042	4281	8485	6608	1537	1272	754	3498	1612	1961	7365	17252	793	743	4874	1954	4586	10129	8147	6833	2260	1168
2043	4266	8450	6585	1531	1267	752	3481	1606	1954	7365	17186	784	734	4778	1951	4586	10129	8147	6818	2257	1151
2044	4251	8410	6562	1526	1263	749	3458	1600	1947	7365	17115	773	724	4687	1947	4586	10129	8147	6803	2257	1132
2045	4236	8365	6539	1521	1258	746	3431	1595	1940	7365	17040	764	715	4601	1943	4586	10129	8147	6784	2257	1114
2046	4222	8318	6516	1515	1254	744	3401	1589	1933	7365	16962	755	706	4520	1940	4586	10129	8147	6779	2257	1099
2047	4207	8273	6493	1510	1249	741	3374	1584	1926	7365	16887	746	698	4443	1937	4583	10129	8147	6774	2256	1086
2048	4192	8233	6470	1505	1245	739	3352	1578	1920	7365	16817	738	691	4370	1934	4570	10129	8147	6774	2255	1074
2049	4177	8198	6448	1499	1241	736	3333	1573	1913	7364	16751	732	685	4301	1931	4543	10129	8147	6668	2254	1065
2050	4168	8175	6432	1496	1238	734	3322	1569	1909	7364	16709	728	681	4250	1929	4519	10129	8147	6562	2252	1058
2051	4153	8148	6410	1491	1233	734	3312	1563	1902	7364	16652	720	674	4199	1926	4487	10129	8147	6442	2250	1050
2052	4143	8132	6395	1487	1231	728	3307	1560	1897	7364	16616	714	669	4150	1924	4470	10129	8147	6428	2249	1043
2053	4124	8100	6365	1480	1225	728	3298	1552	1889	7364	16545	703	658	4100	1921	4433	10129	8147	6413	2247	1032
2054	4114	8084	6350	1477	1222	723	3293	1549	1884	7364	16509	697	654	4052	1920	4414	10129	8147	6413	2245	1026
2055	4105	8068	6335	1473	1219	723	3288	1545	1880	7364	16473	692	649	4004	1918	4395	10129	8147	6413	2244	1021

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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	8265	2642	5682	11662	-	8663	9787	2385
2023	4951	10486	7725	1661	1590	1000	4325	1755	2136	8646	21073	1514	1400	7862	2586	5128	10973	-	8152	8591	2346
2024	4908	10442	7699	1656	1534	959	4297	1727	2096	8562	20963	1413	1309	7459	2378	4645	11075	-	8122	8067	2199
2025	4830	10228	7570	1653	1478	917	4269	1717	2074	8281	20460	1323	1228	7056	2180	4192	10750	-	7988	7277	2064
2026	4719	9848	7341	1654	1423	875	4241	1726	2070	7813	19577	1243	1158	6654	1999	3783	10435	-	7754	6267	1912
2027	4608	9590	7131	1641	1376	834	4220	1718	2065	7510	18982	1161	1086	6251	1874	3475	10129	-	7600	5511	1729
2028	4529	9451	6991	1626	1345	792	4206	1705	2059	7363	18662	1079	1013	6052	1799	3274	10129	-	7524	4903	1516
2029	4481	9426	6916	1608	1331	790	4199	1687	2052	7363	18605	1012	953	5825	1775	3176	10129	-	7524	4263	1353
2030	4465	9152	6892	1603	1326	787	3946	1681	2045	7363	18297	946	894	5597	1756	3111	10129	14369	7524	3752	1230
2031	4449	8822	6868	1597	1322	784	3639	1675	2038	7363	17933	895	848	5400	1740	3061	10129	10937	7524	3424	1158
2032	4434	8478	6843	1592	1317	781	3318	1669	2030	7363	17555	840	799	5255	1726	3019	10129	9219	7524	3410	1093
2033	4418	8377	6820	1586	1312	779	3236	1663	2023	7356	17423	806	766	5118	1713	2981	10129	7501	7524	3399	1051
2034	4403	8328	6796	1580	1308	776	3205	1657	2016	7300	17342	778	740	5002	1703	2946	10129	7501	7524	3389	1022
2035	4388	8289	6772	1575	1303	773	3185	1652	2009	7202	17271	759	722	4884	1694	2914	10129	7435	7524	3382	1000
2036	4372	8256	6748	1569	1299	770	3169	1646	2002	7111	17207	744	707	4783	1688	2885	10129	7368	7505	3376	983
2037	4357	8224	6725	1564	1294	768	3155	1640	1995	7069	17143	730	694	4681	1682	2859	10129	7301	7481	3371	966
2038	4342	8195	6701	1558	1289	765	3144	1634	1988	7069	17083	717	682	4587	1678	2834	10129	7301	7458	3367	950
2039	4326	8160	6678	1553	1285	762	3127	1629	1981	7069	17017	706	671	4468	1675	2811	8814	7301	7455	3363	936
2040	4311	8128	6654	1548	1280	760	3113	1623	1974	7069	16954	697	662	4350	1671	2791	7669	7301	7455	3360	925
2041	4296	8097	6631	1542	1276	757	3098	1617	1967	7069	16891	687	652	4219	1668	2771	6673	7301	7455	3357	913
2042	4281	8072	6608	1537	1272	754	3091	1612	1961	7069	16836	678	644	4108	1665	2753	5807	7301	7102	3355	902
2043	4266	8047	6585	1531	1267	752	3084	1606	1954	7069	16780	668	635	3991	1662	2736	5053	7301	6742	3354	891
2044	4251	8022	6562	1526	1263	749	3076	1600	1947	7069	16725	660	627	3899	1658	2721	4397	7301	6382	3354	882
2045	4236	7998	6539	1521	1258	746	3069	1595	1940	7069	16670	652	619	3812	1653	2706	3826	7301	6367	3353	871
2046	4222	7974	6516	1515	1254	744	3062	1589	1933	7069	16616	646	613	3741	1648	2687	3329	7301	6359	3352	863
2047	4207	7949	6493	1510	1249	741	3055	1584	1926	7069	16561	637	605	3673	1644	2665	2897	7301	6351	3352	854
2048	4192	7925	6470	1505	1245	739	3048	1578	1920	7069	16507	630	598	3610	1640	2641	2520	7301	6351	3351	845
2049	4177	7901	6448	1499	1241	736	3041	1573	1913	7036	16453	621	590	3549	1635	2621	2193	7301	6220	3349	835
2050	4168	7885	6432	1496	1238	734	3036	1569	1909	7002	16417	615	585	3498	1633	2609	1908	7301	6090	3347	829
2051	4153	7861	6410	1491	1233	734	3029	1563	1902	6969	16364	612	581	3448	1630	2599	1908	7301	5960	3346	825
2052	4143	7846	6395	1487	1231	728	3025	1560	1897	6969	16328	611	580	3398	1629	2595	1890	7301	5960	3345	823
2053	4124	7815	6365	1480	1225	728	3016	1552	1889	6969	16257	608	578	3349	1626	2586	1890	7301	5960	3343	821
2054	4114	7799	6350	1477	1222	723	3012	1549	1884	6969	16222	607	577	3301	1625	2582	1881	7301	5960	3343	820
2055	4105	7784	6335	1473	1219	723	3008	1545	1880	6969	16187	606	576	3253	1623	2578	1881	7301	5960	3342	819

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 (15hrs)	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
2022	5398	11040	8180	1766	1499	943	4354	2004	2438	7825	21935	1572	1454	8265	2642	5682	11662	-	8663	9787	2385
2023	4951	10486	7725	1661	1590	1000	4325	1755	2136	8646	21073	1514	1400	7862	2586	5475	10973	-	8152	8591	2346
2024	4908	10378	7699	1656	1534	959	4297	1727	2096	8564	20898	1418	1313	7459	2416	5278	10933	-	8122	8080	2204
2025	4830	10041	7570	1653	1478	917	4269	1717	2074	8287	20271	1337	1240	7056	2254	5086	10754	-	7988	7313	2076
2026	4719	9484	7341	1654	1423	875	4241	1726	2070	7824	19211	1271	1182	6654	2102	4901	10438	-	7754	6334	1964
2027	4608	9093	7131	1641	1376	834	4220	1718	2065	7524	18481	1216	1133	6251	1991	4707	10231	-	7600	5574	1860
2028	4529	8864	6991	1626	1345	792	4178	1705	2059	7378	18071	1157	1080	6105	1917	4528	10129	-	7524	4959	1755
2029	4481	8786	6916	1608	1331	790	4136	1687	2052	7378	17961	1098	1027	5984	1881	4386	10129	-	7524	4122	1653
2030	4465	8729	6892	1603	1326	787	4012	1681	2045	7377	17872	1041	976	5833	1851	4306	10129	7355	7524	3426	1557
2031	4449	8688	6868	1597	1322	784	3891	1675	2038	7375	17798	997	936	5653	1830	4269	10129	7352	7524	2897	1476
2032	4434	8662	6843	1592	1317	781	3775	1669	2030	7374	17740	967	907	5460	1816	4254	10129	7351	7524	2862	1409
2033	4418	8637	6820	1586	1312	779	3661	1663	2023	7374	17684	941	882	5291	1809	4247	10129	7351	7524	2833	1349
2034	4403	8612	6796	1580	1308	776	3485	1657	2016	7374	17627	927	868	5149	1802	4238	10129	7351	7250	2808	1308
2035	4388	8576	6772	1575	1303	773	3467	1652	2009	7374	17560	899	842	5033	1788	4185	10129	7350	6976	2785	1263
2036	4372	8539	6748	1569	1299	770	3448	1646	2002	7373	17491	871	816	4945	1770	4104	10129	7348	6695	2762	1225
2037	4357	8501	6725	1564	1294	768	3428	1640	1995	7373	17422	838	786	4864	1750	4004	10129	7344	6687	2741	1184
2038	4342	8474	6701	1558	1289	765	3419	1634	1988	7373	17364	820	770	4793	1736	3928	10129	7341	6680	2721	1157
2039	4326	8448	6678	1553	1285	762	3411	1629	1981	7373	17307	802	754	4719	1727	3870	9116	7336	6678	2703	1130
2040	4311	8423	6654	1548	1280	760	3403	1623	1974	7373	17250	785	738	4657	1716	3822	8204	7333	6678	2691	1106
2041	4296	8286	6631	1542	1276	757	3286	1617	1967	7373	17082	768	723	4585	1707	3784	7383	7330	6678	2684	1084
2042	4281	8144	6608	1537	1272	754	3163	1612	1961	7373	16909	751	708	4512	1700	3752	6644	7328	6659	2681	1065
2043	4266	8001	6585	1531	1267	752	3038	1606	1954	7373	16734	735	693	4435	1694	3714	5980	7328	6633	2678	1046
2044	4251	7968	6562	1526	1263	749	3023	1600	1947	7372	16670	720	679	4364	1688	3656	5382	7328	6608	2675	1027
2045	4236	7940	6539	1521	1258	746	3012	1595	1940	7360	16612	704	665	4301	1682	3573	4843	7328	6594	2672	1009
2046	4222	7913	6516	1515	1254	744	3003	1589	1933	7329	16555	689	651	4226	1680	3484	4359	7328	6585	2669	991
2047	4207	7888	6493	1510	1249	741	2994	1584	1926	7279	16499	674	637	4141	1676	3407	3923	7328	6577	2667	974
2048	4192	7863	6470	1505	1245	739	2986	1578	1920	7241	16444	660	624	4040	1672	3350	3530	7328	6577	2665	958
2049	4177	7838	6448	1499	1241	736	2978	1573	1913	7170	16389	645	611	3943	1667	3305	3177	7328	6433	2662	943
2050	4168	7821	6432	1496	1238	734	2973	1569	1909	7118	16352	636	602	3874	1664	3279	2859	7328	6289	2658	932
2051	4153	7797	6410	1491	1233	734	2966	1563	1902	7066	16298	629	596	3806	1661	3258	2859	7328	6145	2653	925
2052	4143	7781	6395	1487	1231	728	2961	1560	1897	7066	16263	627	594	3740	1659	3248	2789	7328	6145	2650	922
2053	4124	7750	6365	1480	1225	728	2952	1552	1889	7066	16192	623	590	3675	1655	3229	2789	7328	6145	2644	918
2054	4114	7734	6350	1477	1222	723	2948	1549	1884	7066	16156	621	588	3611	1653	3218	2771	7328	6145	2641	915
2055	4105	7718	6335	1473	1219	723	2943	1545	1880	7065	16121	619	587	3548	1650	3208	2771	7328	6145	2637	914

Apx Table B.4 One and two hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	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
2022	931	931	931	431	431	431	500	500	500	673	673	673	418	418	418	255	255	255
2023	935	935	935	440	440	440	495	495	495	676	676	676	426	426	426	250	250	250
2024	879	879	879	412	412	412	467	467	467	635	635	635	399	399	399	236	236	236
2025	830	830	830	386	386	386	444	444	444	600	600	600	374	374	374	226	226	226
2026	786	786	786	359	359	359	427	427	427	568	568	568	348	348	348	220	220	220
2027	791	752	709	369	330	288	422	422	421	554	538	496	336	320	279	218	218	217
2028	773	721	631	356	304	217	417	416	414	539	510	424	324	295	210	215	215	214
2029	755	691	554	343	281	146	412	411	408	525	484	352	312	272	141	212	212	211
2030	737	664	533	330	258	131	407	405	402	510	460	334	300	251	127	210	209	207
2031	719	638	515	317	238	119	402	400	396	496	437	320	289	231	116	207	206	204
2032	701	614	499	304	219	110	397	395	390	481	416	308	277	213	106	205	204	201
2033	683	592	493	291	202	109	392	389	384	467	397	303	265	196	105	202	201	198
2034	665	571	486	278	186	108	387	384	378	453	379	299	253	181	104	200	198	195
2035	647	561	479	265	181	107	382	379	372	438	371	296	241	176	104	197	196	192
2036	629	549	473	252	175	106	377	374	367	424	363	292	229	170	103	195	193	189
2037	612	540	466	239	170	105	373	369	361	410	356	288	218	165	102	192	191	186
2038	595	529	460	227	165	104	368	364	355	397	348	285	207	160	101	190	188	183
2039	582	521	454	218	161	104	363	360	350	386	342	281	199	156	101	187	186	181
2040	568	512	448	209	157	103	359	355	345	375	335	278	190	152	100	185	183	178
2041	557	504	442	202	154	102	354	350	339	367	330	274	184	149	99	183	181	175
2042	550	499	436	200	153	102	350	346	334	363	327	271	182	148	99	181	178	172
2043	544	493	431	198	152	102	346	341	329	359	324	269	181	148	99	178	176	170
2044	534	487	426	192	150	101	341	337	324	351	319	266	175	145	98	176	174	167
2045	525	480	420	188	148	101	337	332	319	345	315	263	171	144	98	174	171	165
2046	518	475	415	185	147	101	333	328	314	341	312	260	169	143	98	172	169	162
2047	512	470	410	183	146	101	329	323	310	337	309	257	167	142	98	170	167	160
2048	507	464	405	182	145	100	325	319	305	333	306	255	165	141	97	168	165	157
2049	501	460	400	181	145	100	321	315	300	330	303	252	164	140	97	165	163	155
2050	496	455	396	179	144	100	317	311	296	327	300	250	163	140	97	163	160	153
2051	495	454	395	179	144	100	316	311	296	326	300	249	163	139	97	163	160	153
2052	494	454	395	179	144	100	315	311	296	325	300	249	163	139	97	163	160	153
2053	493	454	395	177	143	100	315	311	296	324	299	249	161	139	97	163	160	153
2054	493	454	395	177	143	100	315	311	296	324	299	249	161	139	97	163	160	153
2055	492	453	395	176	142	100	315	311	296	323	299	249	161	138	97	163	160	153

Apx Table B.5 Four and eight hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	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
2022	546	546	546	411	411	411	135	135	135	485	485	485	404	404	404	81	81	81
2023	549	549	549	419	419	419	130	130	130	487	487	487	412	412	412	75	75	75
2024	516	516	516	393	393	393	123	123	123	458	458	458	386	386	386	72	72	72
2025	487	487	487	368	368	368	119	119	119	433	433	433	361	361	361	71	71	71
2026	461	461	461	342	342	342	119	119	119	410	410	410	336	336	336	74	74	74
2027	448	433	392	330	315	274	118	118	118	397	382	342	325	310	270	73	73	73
2028	441	412	326	324	295	210	116	116	116	396	367	282	324	295	210	72	72	71
2029	427	387	256	312	272	141	115	115	114	383	343	212	312	272	141	71	71	70
2030	414	364	239	300	251	127	114	113	112	371	321	196	300	251	127	70	70	69
2031	401	343	226	289	231	116	112	112	111	358	300	184	289	231	116	69	69	68
2032	388	323	215	277	213	106	111	110	109	345	281	174	277	213	106	68	68	67
2033	374	305	213	265	196	105	109	109	107	332	263	172	265	196	105	67	67	66
2034	361	288	210	253	181	104	108	107	106	320	247	170	253	181	104	67	66	65
2035	348	282	208	241	176	104	107	106	104	307	241	168	241	176	104	66	65	64
2036	335	274	205	229	170	103	105	105	102	294	234	166	229	170	103	65	65	63
2037	322	268	203	218	165	102	104	103	101	282	229	164	218	165	102	64	64	62
2038	310	262	201	207	160	101	103	102	99	270	223	163	207	160	101	63	63	61
2039	300	257	198	199	156	101	102	101	98	261	218	161	199	156	101	63	62	60
2040	290	251	196	190	152	100	100	99	96	252	213	159	190	152	100	62	61	59
2041	283	247	194	184	149	99	99	98	95	245	209	158	184	149	99	61	60	58
2042	280	245	192	182	148	99	98	97	93	243	208	157	182	148	99	60	60	58
2043	277	243	191	181	148	99	97	95	92	240	206	156	181	148	99	60	59	57
2044	270	239	189	175	145	98	95	94	91	234	203	154	175	145	98	59	58	56
2045	265	237	187	171	144	98	94	93	89	229	201	153	171	144	98	58	57	55
2046	262	234	186	169	143	98	93	92	88	226	199	152	169	143	98	57	56	54
2047	259	232	184	167	142	98	92	90	87	224	197	151	167	142	98	57	56	53
2048	256	230	183	165	141	97	91	89	85	221	196	150	165	141	97	56	55	53
2049	254	228	181	164	140	97	90	88	84	220	195	149	164	140	97	55	54	52
2050	252	227	180	163	140	97	89	87	83	218	193	148	163	140	97	55	54	51
2051	251	226	179	163	139	97	88	87	83	217	193	148	163	139	97	54	54	51
2052	251	226	179	163	139	97	88	87	83	217	193	148	163	139	97	54	54	51
2053	250	226	179	161	139	97	88	87	83	216	192	148	161	139	97	54	54	51
2054	250	226	179	161	139	97	88	87	83	216	192	148	161	139	97	54	54	51
2055	249	225	179	161	138	97	88	87	83	215	192	148	161	138	97	54	54	51

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
2022	2888	3138	3369	4404	2730	6616	3043	481	392	281	183	114	138	64
2023	2798	3041	3265	4268	2646	6411	2949	466	380	272	178	110	134	62
2024	2709	2944	3161	4131	2561	6206	2855	452	368	263	172	107	129	60
2025	2620	2847	3056	3995	2477	6001	2761	437	356	255	166	103	125	58
2026	2530	2750	2952	3859	2392	5797	2666	422	344	246	161	100	121	56
2027	2441	2652	2848	3722	2308	5592	2572	407	332	237	155	96	116	54
2028	2437	2648	2843	3716	2304	5582	2568	406	331	237	155	96	116	54
2029	2432	2643	2838	3710	2300	5573	2563	405	330	236	155	96	116	54
2030	2428	2639	2833	3703	2296	5563	2559	405	330	236	154	96	116	54
2031	2424	2634	2828	3697	2292	5554	2555	404	329	236	154	96	116	54
2032	2420	2630	2823	3691	2288	5544	2550	403	329	235	154	95	116	54
2033	2416	2625	2819	3684	2284	5535	2546	403	328	235	154	95	115	54
2034	2412	2621	2814	3678	2280	5525	2542	402	328	234	153	95	115	53
2035	2408	2616	2809	3672	2277	5516	2537	401	327	234	153	95	115	53
2036	2404	2612	2804	3666	2273	5506	2533	401	326	234	153	95	115	53
2037	2399	2607	2799	3659	2269	5497	2529	400	326	233	152	95	115	53
2038	2395	2603	2795	3653	2265	5488	2524	399	325	233	152	94	114	53
2039	2391	2599	2790	3647	2261	5478	2520	399	325	232	152	94	114	53
2040	2387	2594	2785	3641	2257	5469	2516	398	324	232	152	94	114	53
2041	2383	2590	2780	3634	2253	5460	2511	397	324	232	151	94	114	53
2042	2379	2585	2776	3628	2249	5450	2507	397	323	231	151	94	114	53
2043	2375	2581	2771	3622	2246	5441	2503	396	323	231	151	94	113	53
2044	2371	2577	2766	3616	2242	5432	2499	395	322	231	151	93	113	53
2045	2367	2572	2761	3610	2238	5423	2494	394	322	230	150	93	113	52
2046	2363	2568	2757	3604	2234	5413	2490	394	321	230	150	93	113	52
2047	2359	2563	2752	3597	2230	5404	2486	393	320	229	150	93	113	52
2048	2355	2559	2747	3591	2227	5395	2482	392	320	229	150	93	112	52
2049	2351	2555	2743	3585	2223	5386	2477	392	319	229	149	93	112	52
2050	2347	2550	2738	3579	2219	5377	2473	391	319	228	149	92	112	52
2051	2343	2546	2733	3573	2215	5368	2469	390	318	228	149	92	112	52
2052	2339	2542	2729	3567	2212	5358	2465	390	318	227	149	92	112	52
2053	2335	2537	2724	3561	2208	5349	2461	389	317	227	148	92	111	52
2054	2331	2533	2719	3555	2204	5340	2456	388	317	227	148	92	111	52
2055	2327	2529	2715	3549	2200	5331	2452	388	316	226	148	92	111	52

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

	$/kWh							$/kW						
	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/ CSIRO	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/ CSIRO
Battery (1hr)	1092	870	823	931	-	-	-	1092	870	823	931	-	-	-
Battery (2hrs)	687	583	547	673	-	-	-	1375	1166	1095	1346	-	-	-
Battery (4hrs)	543	464	432	546	-	-	-	2171	1854	1729	2185	-	-	-
Battery (8hrs)	492	409	379	485	-	-	-	3939	3271	3035	3882	-	-	-
PHES (8hrs)	-	-	-	-	275	315	392	-	-	-	-	2203	2520	3138
PHES (12hrs)	-	-	-	-	195	226	281	-	-	-	-	2341	2711	3369
PHES (24hrs)	-	-	-	-	145	147	183	-	-	-	-	3469	3537	4404
PHES (24hrs) Tasmania	-	-	-	-	-	91	114	-	-	-	-	-	2185	2730
PHES (48hrs)	-	-	-	-	81	111	138	-	-	-	-	3887	5313	6616
PHES (48hrs) Tasmania	-	-	-	-	-	51	64	-	-	-	-	-	2468	3043

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1600/kWh (Aurecon, 2022a).

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	
2022												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4354	14.0	80%	4354	20.0	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1766	14.0	80%	1766	20.0	60%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1499	14.0	20%	1499	20.0	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	943	14.0	20%	943	20.0	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	2004	14.0	20%	2004	20.0	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2438	14.6	20%	2438	21.9	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	11040	6.9	80%	11040	10.5	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	5398	6.9	80%	5398	10.5	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8180	0.6	80%	8180	0.7	60%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7825	0.5	80%	7825	2.0	60%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1572	0.0	32%	1572	0.0	22%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	2642	0.0	44%	2642	0.0	35%
Wind offshore	25	3.0	100%	149.9	0.0	0.0	5682	0.0	52%	5682	0.0	40%
2030												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4012	8.0	80%	4192	16.8	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1603	8.0	80%	1603	16.8	60%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1326	8.0	20%	1326	16.8	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	834	8.0	20%	834	16.8	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1681	8.0	20%	1681	16.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2045	14.6	20%	2045	21.9	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8729	2.3	80%	9401	4.0	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4465	2.3	80%	4465	4.0	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6892	0.7	80%	6892	0.7	60%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7363	0.5	80%	7365	2.0	60%
Nuclear (SMR)	30	3.0	35%	200.0	5.3	0.0	7355	0.5	80%	15853	0.7	60%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	946	0.0	32%	1045	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1756	0.0	46%	1996	0.0	35%
Wind offshore	25	3.0	100%	149.9	0.0	0.0	3111	0.0	54%	4608	0.0	40%

2040												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3403	8.2	80%	3591	17.9	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1548	8.2	80%	1548	17.9	60%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1280	8.2	20%	1280	17.9	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	806	8.2	20%	806	17.9	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1623	8.2	20%	1623	17.9	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	1974	11.6	20%	1974	17.4	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8423	1.8	80%	8614	4.0	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4311	1.8	80%	4311	4.0	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6654	0.7	80%	6654	0.7	60%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7069	0.5	80%	7365	2.0	60%
Nuclear (SMR)	30	3.0	40%	200.0	5.3	0.0	7301	0.5	80%	8147	0.7	60%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	697	0.0	32%	806	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1671	0.0	48%	1962	0.0	35%
Wind offshore	25	3.0	100%	149.9	0.0	0.0	2791	0.0	57%	4586	0.0	40%
2050												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3036	8.2	80%	3322	17.9	60%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1496	8.2	80%	1496	17.9	60%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1238	8.2	20%	1238	17.9	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	778	8.2	20%	778	17.9	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1569	8.2	20%	1569	17.9	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	1909	10.2	20%	1909	15.3	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	7885	1.8	80%	8175	4.0	60%
Black coal	30	2.0	40%	53.2	4.2	0.0	4168	1.8	80%	4168	4.0	60%
Brown coal	30	4.0	32%	69.0	5.3	0.0	6432	0.7	80%	6432	0.7	60%
Biomass (small scale)	30	1.3	29%	131.6	8.4	0.0	7002	0.5	80%	7364	2.0	60%
Nuclear (SMR)	30	3.0	45%	200.0	5.3	0.0	7301	0.5	80%	8147	0.7	60%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	615	0.0	32%	728	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1633	0.0	50%	1929	0.0	35%
Wind offshore	25	3.0	100%	149.9	0.0	0.0	2609	0.0	61%	4519	0.0	40%

Notes: 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, 2022-23 $/MWh

Category	Assumption	Technology	2022		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas turbine small	232	292	163	252	163	261	161	259
		Gas turbine large	210	275	137	233	138	243	136	242
		Gas reciprocating	240	293	171	249	170	256	168	254
		H_2 reciprocating	298	381	280	362	243	308	224	281
Flexible 60-80% load, high emission		Black coal	137	192	84	119	78	117	76	115
		Brown coal	129	168	113	146	110	143	107	139
		Gas	126	176	81	151	82	157	81	157
	Climate policy risk premium	Black coal	183	254	123	170	115	166	112	162
		Brown coal	226	297	194	255	189	247	183	240
		Gas	139	194	93	167	94	173	93	172
Flexible 60-80% load, low emission		Black coal with CCS	234	324	152	221	142	208	136	202
		Gas with CCS	179	247	125	218	120	217	115	213
		Nuclear (SMR)			130	311	128	184	128	183
		Biomass (small scale)	121	175	115	168	112	168	111	168
Variable	Standalone	Solar PV	48	70	31	57	25	46	22	43
		Wind onshore	63	80	42	62	39	61	37	60
		Wind offshore	149	194	93	165	82	165	73	163
Variable with integration costs	Wind & solar PV combined	60% share			56	76				
		70% share			58	78				
		80% share			59	80				
		90% share			62	83				

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
2022	1837	3006	1837	3006	1837	3006
2023	1603	2623	1603	2623	1603	2623
2024	1437	2351	1437	2351	1437	2351
2025	1178	2126	1080	2057	1194	2113
2026	980	1923	823	1799	1006	1899
2027	885	1739	656	1574	887	1707
2028	813	1573	596	1377	827	1534
2029	767	1423	543	1205	783	1379
2030	699	1287	498	1054	720	1239
2031	668	1164	465	922	685	1114
2032	634	1052	439	807	656	1001
2033	607	952	415	706	631	900
2034	585	861	394	618	608	809
2035	565	778	369	540	588	727
2036	537	704	347	473	550	653
2037	522	637	328	414	511	587
2038	503	576	311	362	476	528
2039	488	521	296	316	451	474
2040	471	471	277	277	426	426
2041	460	460	255	255	406	406
2042	449	449	237	237	390	390
2043	423	423	224	224	373	373
2044	410	410	212	212	358	358
2045	398	398	202	202	345	345
2046	379	379	194	194	334	334
2047	359	359	184	184	323	323
2048	344	344	176	176	313	313
2049	328	328	168	168	297	297
2050	310	310	156	156	280	280
2051	310	310	156	156	280	280
2052	306	306	151	151	276	276
2053	306	306	151	151	276	276
2054	303	303	147	147	272	272
2055	303	303	147	147	272	272

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 **Conventional geothermal energy**: Australia is relatively geothermally inactive **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
BECCS	Bioenergy carbon capture and storage
BOP	Balance of plant
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CPI	Consumer price index
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
H2	Hydrogen
hrs	Hours
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
ISP	Integrated System plan
kW	Kilowatt

Abbreviation	Meaning
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
Li-ion	Lithium-ion
LR	Learning Rate
Mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NSW	New South Wales
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
WA	Western Australia
WEO	World Energy Outlook

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