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Consultation draft

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Acknowledgement

CSIRO acknowledges the Traditional Owners of the lands that we live and work on across Australia and pays its respect to Elders past and present

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Foreword

Assumptions about the cost of electricity generation and storage technologies are a key input to any electricity system planning exercise in Australia or around the world. The primary role of GenCost is to provide capital cost data for the electricity modelling and planning community. The project delivers the capital cost data with an emphasis on stakeholder consultation, recognising that no single organisation can be completely across the changing circumstances of all relevant technologies.

A secondary goal of the project is to provide an indicator of what the capital cost data means for the cost of delivered electricity and the relative competitiveness of generation technologies. This function is delivered by calculating a metric called the levelised cost of electricity (LCOE) which is the minimum per unit price that a project requires to pay back its investment and running costs over its life. LCOE typically only consider a small number of core project details with the more minor or unique costs of each project ignored so that costs are calculated on a simple and common basis.

GenCost also provides a system levelised cost of electricity (SLCOE) which is the average cost of electricity from a bundle of electricity generation and storage technologies that together meet all the requirements of the electricity system. Electricity systems will always require a diversity of resources to deliver all their functions and so no single technology will meet all the system's needs regardless of its relative cost position.

Consultation

This consultation draft is being provided for stakeholders to consider and provide feedback. For instructions on how to provide feedback and the consultation schedule, please go to https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-forecasting-assumptions-update.

Executive summary

Technological change in electricity generation is a global effort that is strongly linked to global climate change policy ambitions. While the rate of change remains uncertain and the level of commitment of each country varies over time, in broad terms, there is continued support for collective action limiting global average temperature increases. 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 PV) 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.

Purpose and scope

GenCost is a collaboration between CSIRO and AEMO to deliver an annual process of updating the capital costs of electricity generation, energy storage and hydrogen production technologies with a strong emphasis on stakeholder engagement. GenCost represents Australia's most comprehensive electricity generation cost projection report. It uses the best available information each cycle to provide an objective annual benchmark on cost projections and updates forecasts accordingly to guide decision making, given technology costs change each year. This is the seventh 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 have made consultation an important part of the process of updating data and projections.

The report encompasses updated current capital cost estimates commissioned by AEMO and delivered by GHD. 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.

New method for estimating integration costs

This report revises the methodology for estimating the integration costs of renewables and other technologies into the electricity system based on stakeholder feedback. Through various submissions over several years, stakeholders requested that the methodology be revised in two ways:

1. Use a System Levelised Cost of Electricity (SLCOE) approach. A SLCOE takes the cost of electricity directly from an electricity system model by dividing all system costs from multiple existing and new technology deployments by the total useful electricity supply in a given year. This concept is also equivalent to the average annual unit cost of electricity for a given electricity system.

2. Provide greater transparency with regard to the data inputs and the modelling system used.

Separate from these two items the new method also seeks to make electricity system modelling more accessible to stakeholders. To address these objectives, a new open source electricity system model and data set was created to calculate SLCOE, replacing the previous method for estimating the integration costs for solar PV and wind.

The key findings from applying the new costing method are

- The average cost of electricity in the NEM consistent with meeting the 2030 82% renewables target is projected to be $91/MWh including transmission or $81/MWh for wholesale generation cost only.
- To determine the cost of electricity in 2050, we must first determine the efficient contribution of the electricity sector to achieving the net zero by 2050 policy target since that target alone does not define the emissions level for the electricity sector.
- In a whole of economy effort to reach net zero by 2050, the modelling found that it will not be efficient to eliminate all emissions from the electricity sector. It will be more efficient to undertake further abatement elsewhere in the economy.
- The efficient range of emissions intensity of the electricity sector lies somewhere between 0.02tCO_2e/MWh to 0.05tCO_2e/MWh depending on the uncertainty in the whole of economy abatement cost.
- Achieving the electricity sector's efficient role in whole of economy net zero abatement is projected to result in electricity costs in 2050 of between $135/MWh to $148/MWh in the NEM inclusive of new transmission costs or $115/MWh to $124/MWh measured as wholesale generation costs only. For context, in 2024-25, the historical average NEM volume weighted generation price is estimated to be slightly higher than the top end of this range at $129/MWh.
- The combination of solar PV, onshore wind, storage and either natural gas or hydrogen was the least cost technology mix in all cases examined with the addition of carbon capture and storage, offshore wind and nuclear leading to higher average electricity costs. These outcomes are based on average costs. Offshore wind has a much wider capital cost uncertainty range and so could perform better under alternative cost scenarios not explored.
- Achieving weak or no progress in reducing electricity sector emissions in the period between 2030 and 2050 is not efficient for achieving net zero because electricity sector emissions reduction is substantially lower cost than emissions reduction elsewhere in the economy.

These cost estimates do not guarantee future generation prices. Changes in generation prices are also subject to:

- Supply-demand imbalance as a result of too much or too little deployment relative to demand growth and retirements.
- Fuel price and weather volatility.

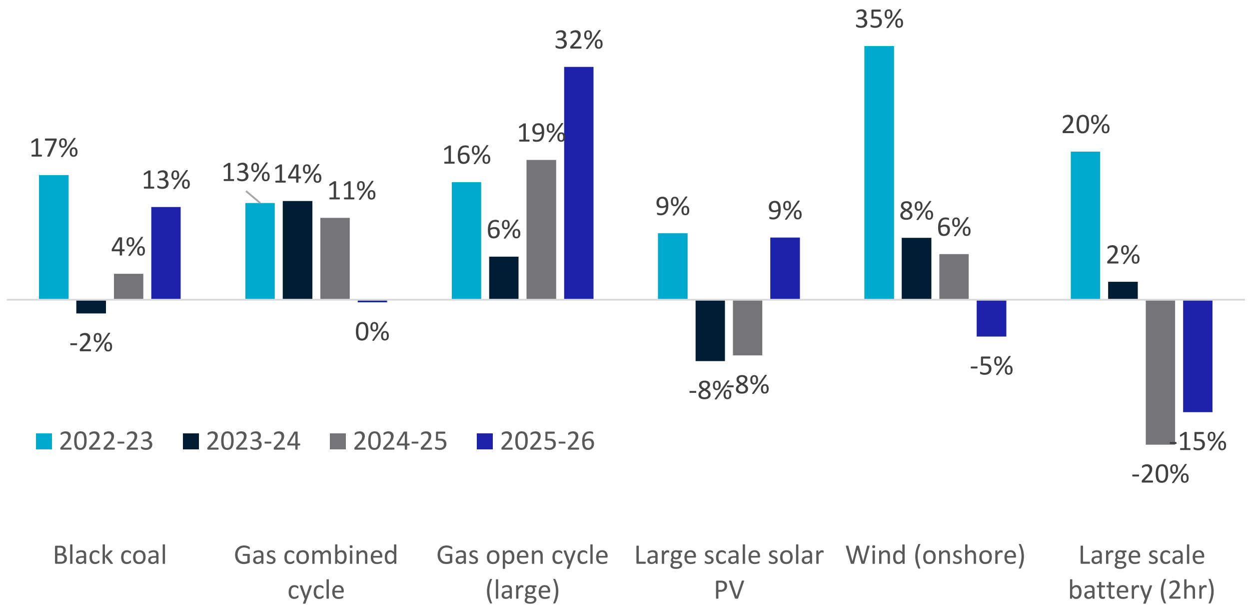
- The level of competition amongst suppliers.

These additional drivers of generation price formation can lead to prices significantly lower or higher than the underlying cost of the system and can take many years to correct due to the long lead times for capacity deployment. Generation prices are currently around 33% of retail prices. Transmission is around 7%, distribution around 34% with the remainder made up of metering, retail services and government programs.

Key changes in capital costs in the past year

The COVID-19 pandemic led to global supply chain constraints which impacted the prices of raw materials needed in technology manufacturing and freight costs. Consequently, past reports have observed consecutive increases in technology costs. For some technologies, the inflationary pressures have progressively eased but the results remain mixed. Technologies have been affected differently because they each have a unique set of material inputs and supply chains.

The biggest recent increases have been in coal and gas open cycle costs. This reflects general increases in gas turbine and steam turbine costs. Battery costs have performed the best in terms of delivering consecutive cost reductions. Onshore wind costs are showing tentative signs of stabilising after experiencing the largest increase in 2022-23.



ES Figure 0-1 Year on year change in current capital costs of selected technologies in the past four years (in real terms)

1 Introduction

Current and projected electricity generation, storage and hydrogen 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 GHD (2025) and further information can be found in their report. The global scenario narratives are outlined in Section 3. Capital cost projection results are reported in Section 4 and LCOE and SLCOE results in Section 5. CSIRO's cost projection methodology is discussed in Appendix A including key global data assumptions. Appendix B provides data tables and this data can also be downloaded from CSIRO's Data Access Portal[1]. A set of technology selection and data quality principles has been included in Appendix C. Feedback on these principles is always welcome.

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, storage and hydrogen technology 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. Appendix E discusses some technology inclusion principles. GenCost does not seek to describe the set of electricity generation and storage technologies included in detail. The report provided by GHD (2025) does include more detailed technology specifications and commentary.

1.1.1 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own resources. AEMO commissioned GHD to provide an update of the current cost and performance characteristics of electricity generation, storage and hydrogen technologies (GHD, 2025). This report focusses on

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

capital costs, but the GHD report provides a wider variety of data such as operating and maintenance costs and energy efficiency. Some of these other data types are used in levelised cost of electricity calculations in Section 5.

Project management, capital cost projections (presented in Section 4), LCOE estimates (Section 5) and development of this report are primarily the responsibility of CSIRO.

1.1.2 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, the main innovation is an update of the method for calculating technology integration costs. The method used up until now was designed in 2018 and its revision and new results are discussed in Section 5. The new method accounts for feedback we received about the previous method and the development of the new method has been separately published in Graham et al. (2025).

1.2 The GenCost mailing list

The GenCost project would not be possible without the input of stakeholders. No single person or organisation can 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.

2 Current technology costs

2.1 Current cost definition

Our definition of current capital costs is 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[2]. 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. In these cases, lower cost quotes will become known 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 GHD (2025). GHD (2025) also provide more detail on specific definitions of the scope of cost categories included. GHD cost estimates are provided for Australia in Australian dollars. They represent the capital costs for a location not greater than 200km from the Victorian metropolitan area. GHD provide adjustments for costs for different regions of the NEM. Site conditions will also impact costs to varying degrees, depending on the technology. CSIRO adjusts the data when used in global modelling to take account of differences in costs in different global regions.

GHD (2025) also provides detailed information on the boundary of capital costs such as what development costs are included, ambient temperature, distance to fuel source and many other considerations.

2.1.1 First-of-a-kind cost premiums

When building a technology that has a degree of novelty, capital cost estimates typically underestimate the realised cost of installation. This is sometimes called an optimism factor or first-of-a-kind (FOAK) costs. These costs are reduced with more installations. The industry term for the point when costs are no longer impacted by the immaturity of the development supply chain is

[2] 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.

nth-of-a-kind (NOAK). The cost estimates in GenCost are mostly on a NOAK basis. This is not because all technologies have mature supply chains but rather because it is too difficult to objectively estimate the FOAK premium that should be applied. It is only observable after a proponent fails to deliver the first project for the cost they had planned. Even then it is difficult to separate optimism from ordinary changes in circumstances, particularly for projects that have long total development times. These cost increases will sometimes be found through the process of more detailed engineering and feasibility studies prior to final investment decisions but may not be shared publicly.

EIA (2023) applies FOAK premiums of up to 25% to their technology costs. AACE (1991) recommends applying different levels of contingency based on the Technology Readiness Level ranging from 10% to up to 70%. In practice, we can find examples of projects that have cost around 100% more than planned such as the Vogtle large-scale nuclear plant in the US and the Snowy 2.0 pumped hydro project in Australia. Flyvbjerg and Gardner (2023) report that the global average cost overrun for nuclear, hydro, wind and solar are 120%, 75%, 13% and 1%, respectively. As such, while special circumstances may have occurred in specific cases, generally, FOAK premiums should be part of normal expectations for estimating the cost of deploying less mature or large technology projects in the future.

The technologies most at risk of FOAK cost premiums in Australia are:

- Offshore wind
- Large-scale nuclear
- Small modular reactor (SMR) nuclear
- Solar thermal
- Coal, gas or biomass with carbon capture and storage
- Wave, tidal and ocean current technologies.

Given the size and unique site conditions of most pumped hydro projects they may also continue to be at risk of cost overruns. However, given these projects are relatively rare, in practice there is not as much difference between a FOAK and NOAK costing.

Technologies that are currently being regularly deployed in Australia such as onshore wind, solar PV, batteries and gas generation are least likely to be impacted. Technologies that have been deployed before and are globally commercially mature may still be subject to FOAK premiums due to large intervals since the last deployment leading to loss of skills, new designs which create uncertainty or new licensing requirements, project size and unique site conditions.

It is likely that 2024 nuclear SMR costs included some FOAK costs given it was based on a FOAK in the US project. However, the first commercial project is proceeding in Canada at Darlington and costs are reduced from the 2024 level to match that project’s costings which include the assumption that they will build each of the four proposed units at lower cost than the previous unit. Regardless of how successful Canada is in reducing costs for each unit build, Australia would still experience a FOAK premium if that technology were to be built for the first time here.

FOAK premiums are very difficult to forecast. However, given stakeholder interest in the technologies listed above, there is a need for an estimate of the FOAK premium (Table 2-1). To develop the premium the value of 120% has been applied to large scale nuclear based on Flyvbjerg and Gardner (2023). The remaining premiums are based on observing the ratio between this large scale nuclear premium and its construction time and applying that ratio to the other technology's construction times. Effectively we are proposing that technologies that take longer to build will face higher FOAK premiums as they are more complex to plan. We then halve the premium for the second project and assume the third and subsequent projects are not impacted by a FOAK premium.

Table 2-1 Suggested FOAK premium by technology

	Construction time	Premium	
Technology	Years	First project	Second project
Gas with CCS	2.0	42%	21%
Black coal with CCS	2.0	42%	21%
Nuclear SMR	4.4	92%	46%
Nuclear large-scale	5.8	120%	60%
Solar thermal	1.8	37%	18%
Wind offshore	3.0	63%	31%

2.2 Capital cost source

AEMO commissioned GHD (2025) 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 GHD (2025) which represents a July estimate and so it is consistent with either the beginning of the financial year 2025-26 or the middle of 2025.

Nuclear technologies are not included in GHD (2025). These are sourced separately by CSIRO.

2.3 Current generation technology capital costs

Figure 2-1 provides capital costs for selected technologies since the project's inception in 2018. All costs are expressed in real 2025-26 Australian dollars, represent overnight costs and do not include any available subsidies.

Costs increased for many technologies from 2022 owing to the global supply chain constraints following the COVID-19 pandemic which also increased freight and raw material costs. Technologies were impacted differently given different input materials and manufacturing regions and are recovering from this development at different rates. The change in current costs over the past four years indicates an easing of inflationary pressures for solar PV, wind and batteries while coal and gas technology costs have recently increased significantly (Figure 2-2). Coal and gas costs are not developed from project data but rather using standard industry software since there are insufficient projects in Australia. In particular, existing coal the projects are very old and therefore unreliable for estimating current costs. The latest updates to industry software included a large upwards revision in gas turbine and steam turbine costs.

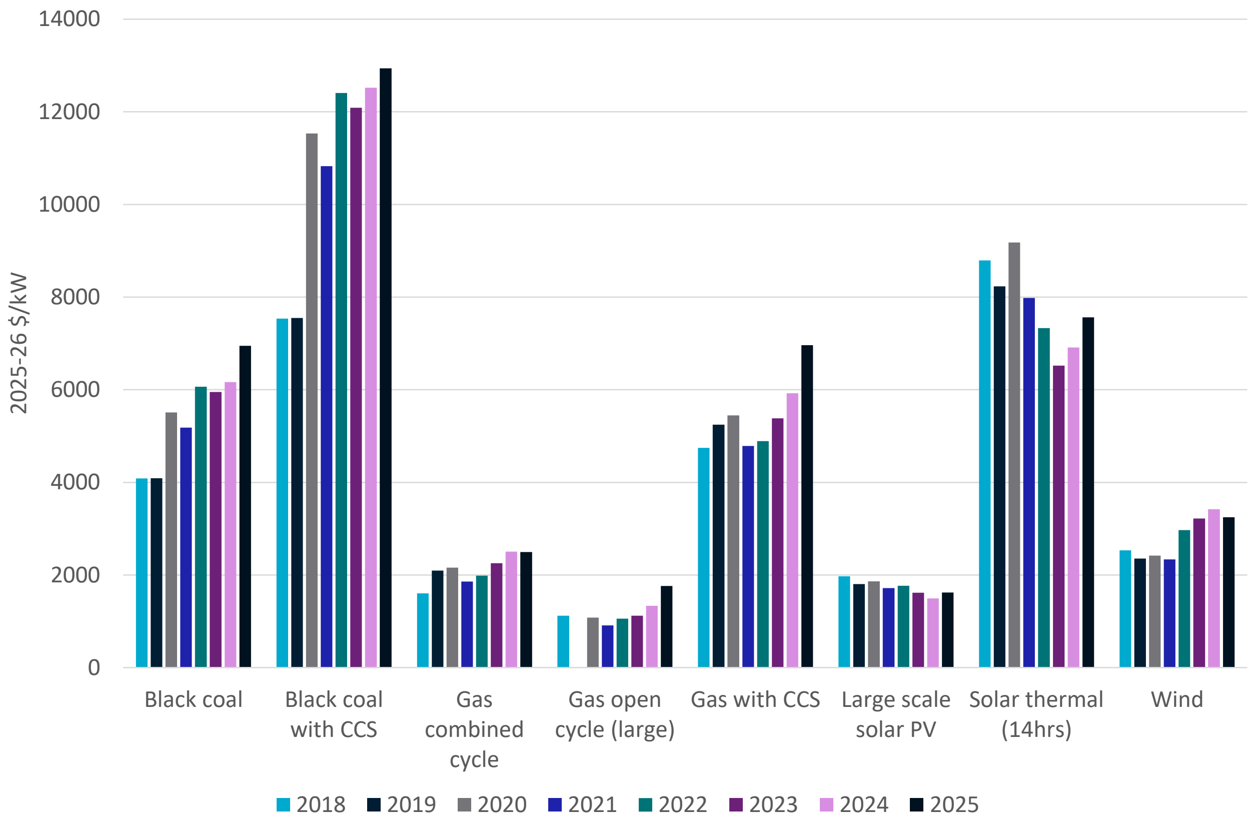


Figure 2-1 Comparison of current capital cost estimates with previous reports (2025-26 $A, FYB)

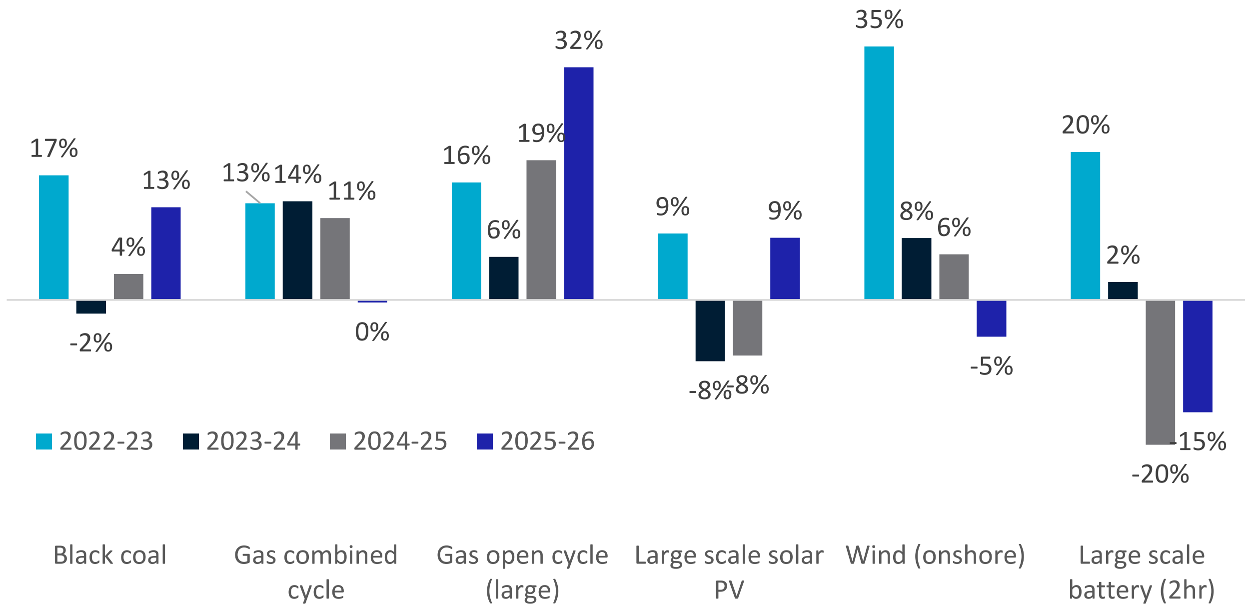


Figure 2-2 Year on year change in current capital costs of selected technologies in the past four years (in real terms)

2.4 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[3] of batteries and pumped hydro energy storage (PHES) in $/kW and $/kWh. GenCost only provides projections for batteries and PHES. Current costs of compressed air energy storage are included in GHD (2025).

None of these capital costs provide enough information to be able to say one technology is more competitive than the other. Capital costs are only one factor. Additional cost factors include energy input costs (where not already included), utilisation rate, round trip efficiency, operating costs and design life.

Total cost basis means that the costs are calculated by taking the total project costs divided by the capacity in kW or kWh[4]. 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).

Note that these $/kWh costs are not for energy delivered but rather a capacity of storage. GenCost does not present levelised costs of storage (LCOS) which are on an energy delivered basis. However, LCOS estimates are available from the CSIRO (2023) *Renewable Energy Storage Roadmap*.

Storage capital 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 deployed in low storage duration applications, while PHES is deployed in high duration applications. A combination of durations may be required by the system depending on the operation of other generation in the system, particularly the scale of variable renewable generation and peaking plant (see Section 5).

[3] 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

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

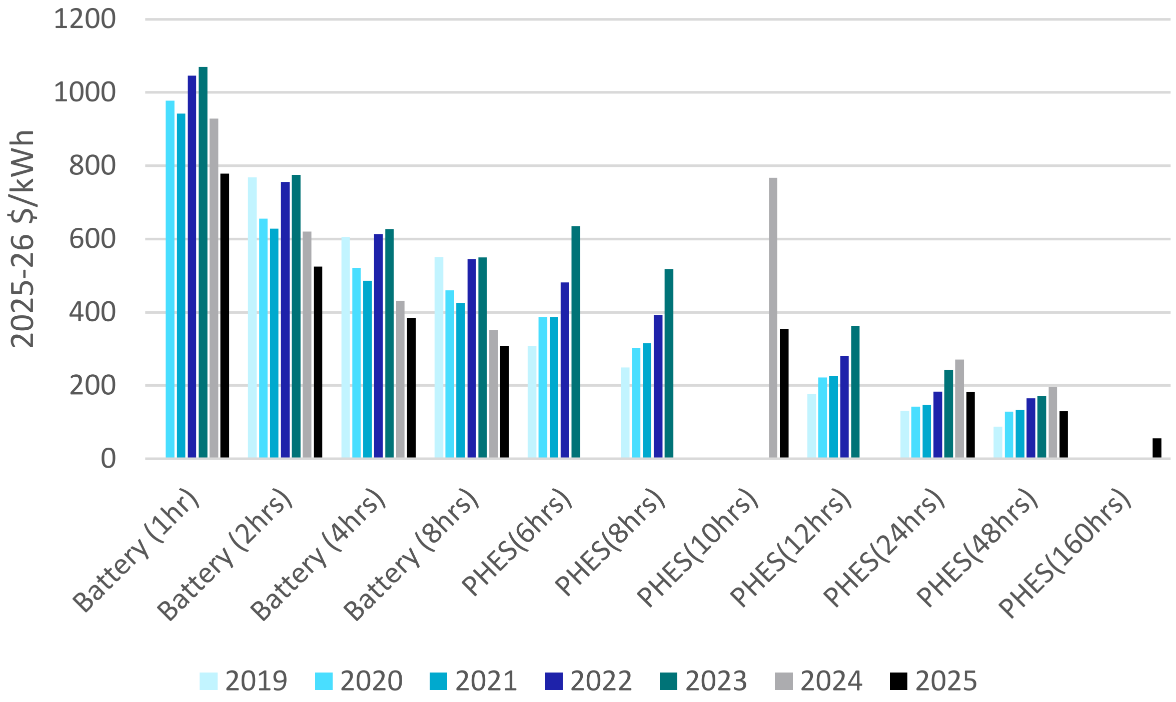


Figure 2-3 Capital costs of storage technologies in $/kWh (total cost basis)

Depth of discharge in batteries can be an important constraint on use. However, all GHD battery costs are presented on a usable capacity basis such that the depth of discharge is 100%[5]. GHD (2025) 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 around a 5% 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.

Battery costs (battery and balance of plant in total) have decreased significantly by 11% to 16% depending on the duration.

[5] 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%.

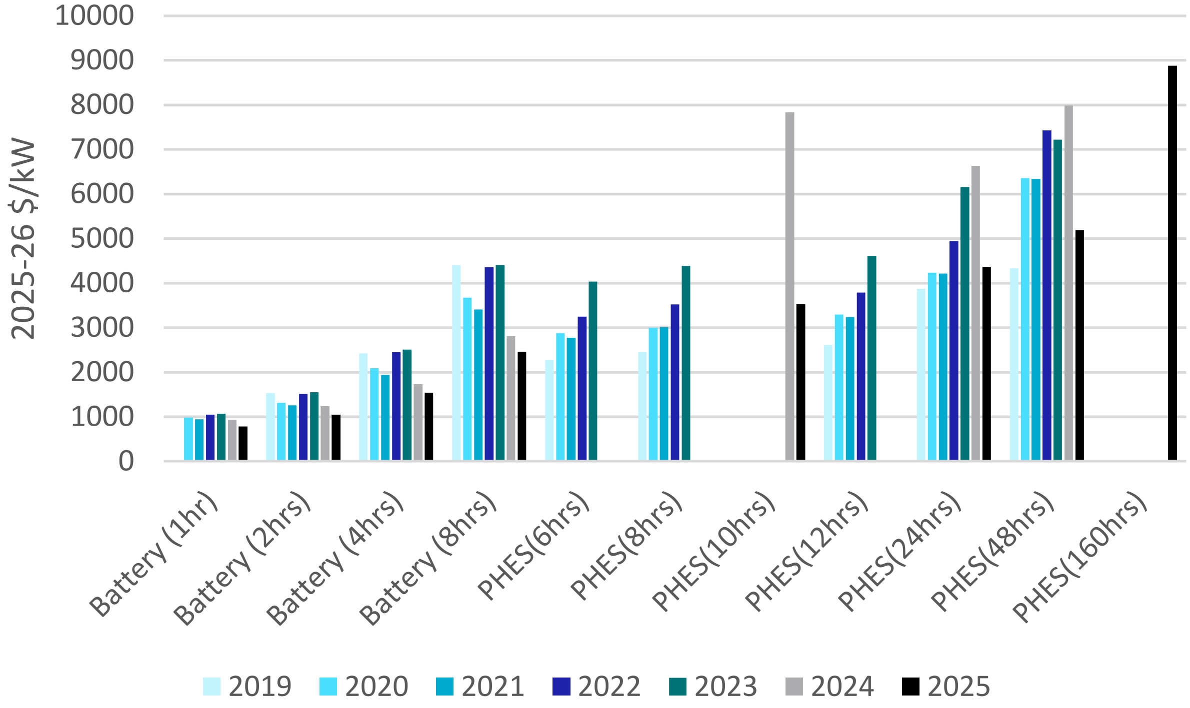


Figure 2-4 Capital costs of storage technologies in $/kW (total cost basis)

PHES current cost estimates have decreased 34% to 55%. The decreases represent a reassessment of costs rather than a change in the technology. See GHD (2025) for details on how the costs were prepared. It is important to note that PHES has 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.

Concentrating solar thermal (CST) is another technology incorporating storage but it is reported as a generation technology in Section 5. It incorporates built-in long-duration energy storage. Direct comparison with the other electricity storage technologies is complicated by the fact that a CST system also collects its own solar energy. Direct comparison with other storage technologies via calculation of the LCOS can be found in CSIRO's *Renewable Energy Storage Roadmap* (CSIRO, 2023), but is outside the scope of GenCost.

3 Scenario narratives and data assumptions

The global scenario narratives included in GenCost have not changed since GenCost 2022-23 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 2024 *World Energy Outlook* (IEA, 2024a) scenario matching to the Stated Policies scenario, Announced Pledges Scenario respectively and Net Zero Emissions by 2050. Various elements, such as the degree of vehicle electrification and hydrogen production, are also consistent with the IEA scenarios. The final GenCost report will update to the 2025 outlook.

3.1.1 Current policies

The *Current policies* scenario includes existing climate policies as at mid-2024 and does not assume that all government targets will be met. The implementation of climate policies in the modelling includes a combination of carbon prices and other climate policies[6]. This scenario has the strongest constraints applied with respect to global variable renewable energy resources and the slowest technology learning rates. This is consistent with a lack of any further progress on emissions abatement beyond recent commitments. 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 governments meeting their Nationally Determined Contributions (NDCs) and longer-term net zero emission targets, which provides the investment signal necessary to deploy low emission technologies. Hydrogen trade (based on a combination of gas with CCS and electrolysis) and transport and industry electrification are higher than in *Current policies*.

3.1.3 Global NZE by 2050

Under the *Global NZE by 2050* scenario there is a strong climate policy consistent with maintaining temperature increases of 1.5 degrees of warming and achieving net zero emissions by 2050

[6] 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.

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	Current policies	Global NZE post 2050	Global NZE by 2050
IEA WEO scenario alignment	Stated policies scenario	Announced pledges scenario	Net zero emission by 2050
CO_2 pricing / climate policy	Based on current policies only	Based on NDCs and announced targets	Consistent with 1.5 degrees world
Renewable energy targets and forced builds / accelerated retirement	Current renewable energy policies	Renewable energy policies extended as needed	High reflecting confidence in renewable energy
Demand / Electrification	Medium	Medium-high	High
Learning rates[1]	Weaker	Normal maturity path	Stronger
Renewable resource & other renewable constraints[2]	More constrained than existing assumptions	Existing constraint assumptions	Less constrained
Decentralisation	More constrained rooftop solar PV constraints[2]	Existing rooftop solar PV constraints[2]	Less constrained rooftop solar photovoltaics (PV)[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 C for assumed learning rates.
2 Existing large-scale and rooftop solar PV renewable generation constraints are as shown in Apx Table C.4.

4 Projection results

All projections start from a current cost and the primary source of 2025 costs is GHD (2025) with data gathered from other sources where otherwise not available in that report. All projections are in real terms. That is, all projected cost changes after 2025 are in addition to the general level of inflation.

4.1 Short-term and long-term inflationary pressures

4.1.1 Short term equipment costs

In recent 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 a trajectory consistent with learning-by-doing and economies of scale.

CSIRO has explored a number of resources to understand cost increases already embedded in technology costs and to project how this current increase in costs will resolve. 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 decade. It is not appropriate to project long-term future costs directly from the top of a price bubble, otherwise all future costs will permanently embed what may be temporary market features.

It is acknowledged that some stakeholders believe the price bubble is not a price bubble but rather a permanent feature that will be built into all future costs. However, to sustain real price increases, supply needs to be either constrained by a cartel (or other persistent market power) or resource scarcity or technology demand needs to grow faster than supply (which implies strong non-linear demand growth since, once established, a given supply capacity can meet linear growth at the rate of that existing capacity[7]). The current cost update indicates inflationary pressures are weakening for at least some technologies.

[7] If the world ramps up to X GW per year technology manufacturing capacity by a certain date, then, without expanding manufacturing capacity any further, it can meet any future capacity target after that date up to the value of bX (where b is the years since the manufacturing capacity was established). The future capacity target would need to include all capacity needed to meet growth as well as replace retiring plant.

Historical experience and the projections available for global clean energy technology deployment do not provide confidence that the required market circumstances for sustained real price increases will prevail for the entire projection period (see Appendix D of the *GenCost 2022-23: Final report* for more discussion on this topic). However, it is considered that the period to 2030 will likely experience extra strong technology deployment. This is partly because of the low global clean technology base (from which non-linear growth is more feasible) but also because governments and industry often use the turning of a decade as a target date for achieving energy targets.

Our current view is that it may take longer than 2030 for technologies to return to a more normal level of costs. This report assumes that if a technology has not already started to show strong signs of recovery it will not return to their normal cost path until 2035. This includes technologies such as onshore wind, coal, gas and nuclear. Note that to achieve a recovery most technologies need only stay constant in nominal prices. This delivers real cost reduction of around 2-3% per year.

A consequence of this modelling approach is that the near-term cost reductions that are shown in the following pages mostly do not reflect learning. Rather, they are predominantly the slow unwinding of inflationary pressures that have temporarily placed costs above the underlying cost curve. Solar PV, batteries, fuel cells and offshore wind have already passed through the global inflationary event and their costs now follow the underlying learning curve cost trajectory.

4.1.2 Long term land and construction costs

Two exceptions where scarcity is a factor and is expected to lead to ongoing real increases in costs is land and construction costs. Land costs generally make up 2% to 9% of generation, storage and electrolyser capital costs. The projections take the land share of capital costs provided in GHD (2025) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[8]. This common land cost index provides some consistency between the treatment of land costs between transmission, generation and storage assets in AEMO's modelling. The inclusion of a specific land cost inflator was first included in the *GenCost 2022-23: Final report*.

Information on future real construction costs become available in a February 2025 report from Oxford Economics Australia (2025), commissioned by AEMO. The data indicates that while construction costs are expected to ease in the short term, a longer term trend of rising real construction costs is projected owing primarily to above inflation growth in construction workers' wages and, to a lesser extent, constrained supply of quarry and cement materials. The construction cost escalation factors estimated by Oxford Economics Australia are applied to the installation cost proportion of capital costs which is sourced from GHD (2025). Note that, this escalation factor is applied after learning. That is, it is still possible for developers to be more productive or innovative at installing some technologies while at the same time facing increases in real costs for some installation components (such as labour). Consequently, mature technologies,

[8] It is referred to as an easement cost index in that document.

which have limited prospect of installation cost reductions, are the most impacted by this new escalation factor (e.g., gas and coal technologies).

4.2 Global generation mix

The rate of global 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.

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[9]. 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 production technology in each scenario indicating the *Global NZE* scenarios are assumed to experience a significant growth in electrolysis hydrogen production. Note that the IEA's estimates of hydrogen demand have decreased relative to the *2023 World Energy Outlook*.

Current policies has the lowest non-hydro renewable share at 53% 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 emissions intensity. In absolute capacity terms, nuclear is 9% of generation in 2030 but declines to 4% to 5% by 2050 reflecting its relatively slower installation rate as electrification causes demand to grow rapidly in the 2030s and 2040s.

[9] 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.

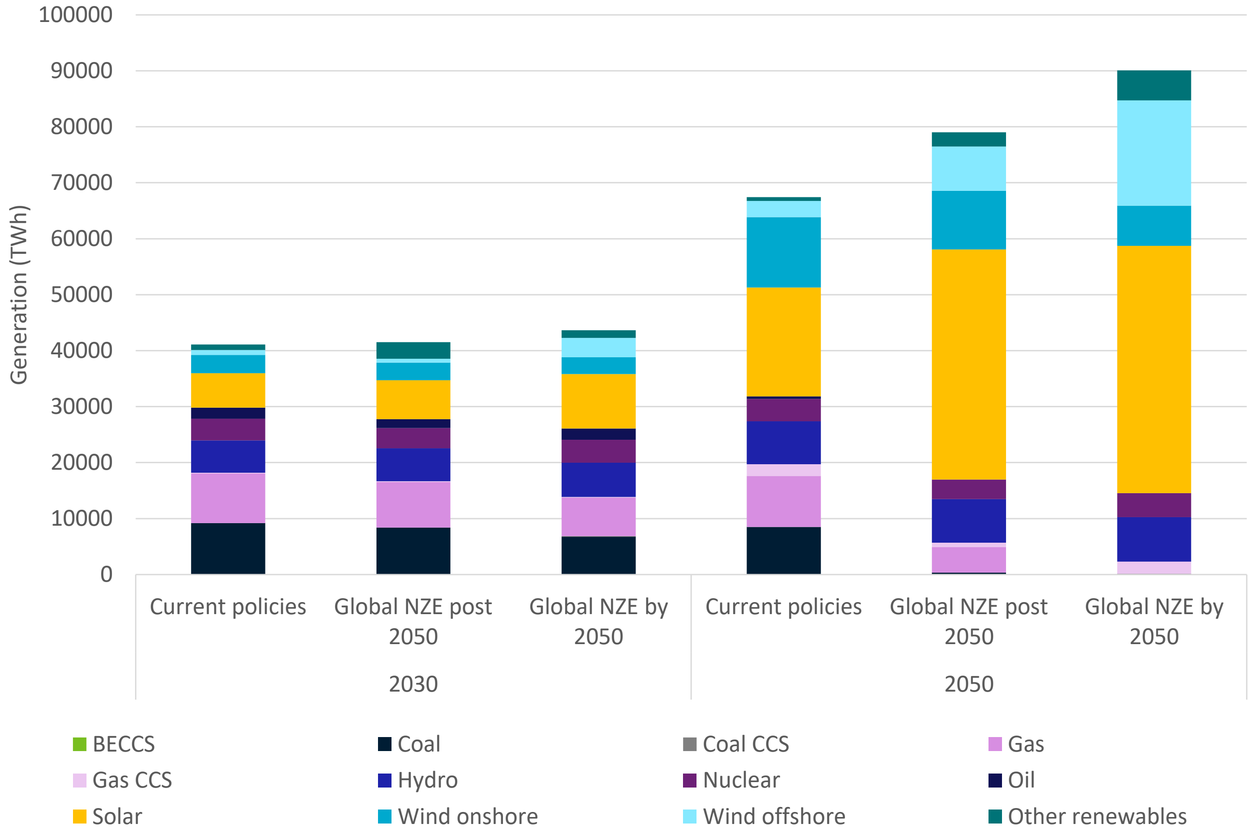


Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

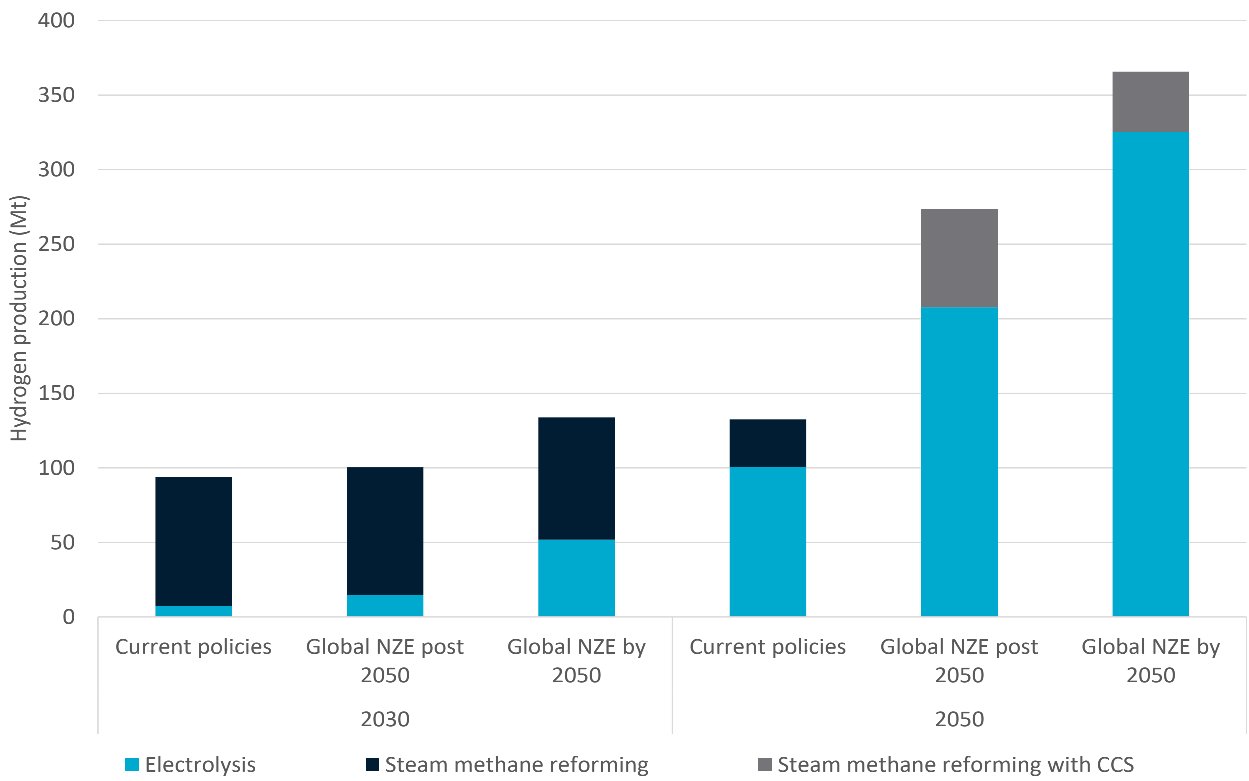


Figure 4-2 Global hydrogen production by technology and scenario, Mt

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. All generation from fossil fuel sources is with CCS accounting for 3% of generation by 2050. Offshore wind features strongly in this scenario at 21% of generation by 2050. Renewables other than hydro, biomass, wind and solar are 6% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs. CCS costs are also impacted by the use of CCS in hydrogen production and other industries.

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2055 compared to the 2024-25 projections. For mature technologies, differences mainly reflect any changes in current costs, an assumed return to normal costs by 2035 and land and construction costs increases thereafter.

Less mature technologies include learning components in addition to the land and construction cost escalators. For technologies with high learning potential, the cost reduction from learning more than offsets the escalation factors for most of the projection period. For those with lower learning potential, the cost changes may cancel one another out.

Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[10].

4.3.1 Black coal ultra-supercritical

The updated cost of black coal ultra-supercritical plant in 2025 has been sourced from GHD (2025). This included a substantial increase based on updates to standard software used to model coal generation capital costs. From 2025, the capital cost is assumed to return to levels consistent with ultra-supercritical prior to the COVID-19 pandemic by 2035 adjusted for changes in construction costs. Black coal ultra-supercritical is treated in the projections as a learning technology. However, global new building of ultra-supercritical coal is limited due to climate change policies and the learning rate is low. The outlook for costs in all scenarios is increasing due to increasing land and installation costs. Installation costs are rising faster the stronger the climate policy ambition of the scenario reflecting a stronger rate of electricity sector construction activity.

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

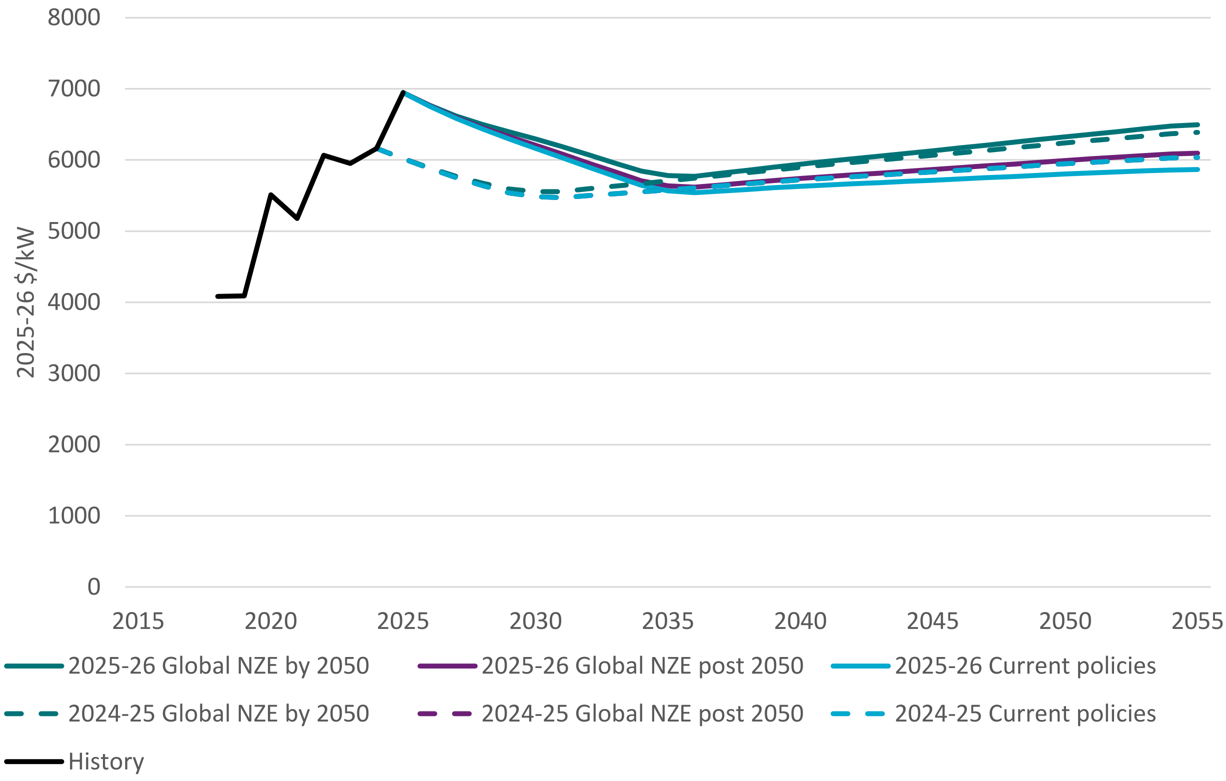


Figure 4-3 Projected capital costs for black coal ultra-supercritical by scenario compared to 2024-25 projections

4.3.2 Coal with CCS

The capital cost of black coal with CCS from 2025 to 2035 has been updated according to the approach outlined in the beginning of this section. Thereafter, the capital cost of the mature parts of the plant reflects assumed land and installation cost increases. For the CCS components, in addition to these changes in land and installation costs, changes in equipment costs are a function of global deployment of gas and coal with CCS, steam methane reforming with CCS and other industry applications of CCS. Compared to the 2024-25 projections, global CCS deployment has not significantly changed.

Current policies has no uptake of steam methane reforming with CCS in hydrogen production. Consequently, any equipment cost reductions from the late 2030s are mainly driven by the deployment of CCS in other industries. While black coal with CCS benefits from co-learning from deployment of CCS in non-electricity industries, there is only a negligible amount of generation from black coal with CCS throughout the projection period.

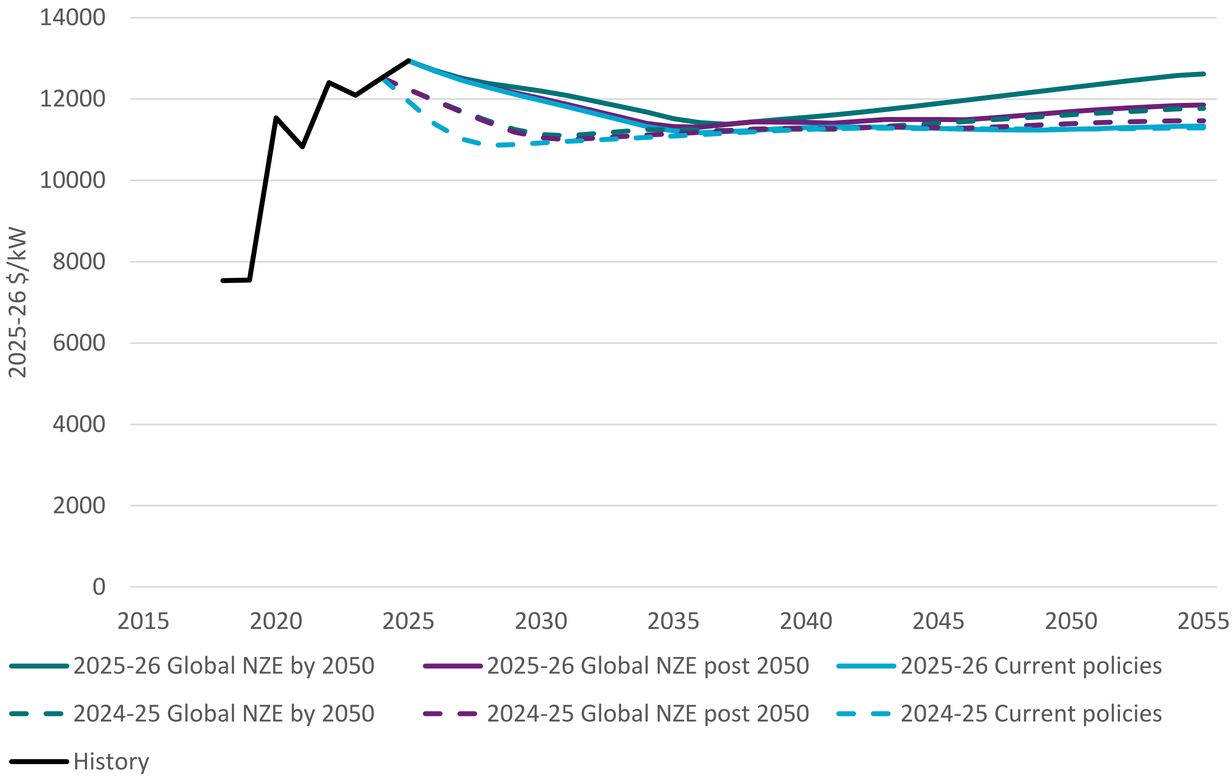


Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2024-25 projections

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). The total CCS deployment in electricity generation and hydrogen production is higher in *Global NZE by 2050.* However, CCS deployment in other industries is higher in *Global NZE post 2050*. Subsequently, those scenarios experience a similar amount of equipment cost reduction by 2050 but with stronger local construction cost increases in *Global NZE by 2050*. In *Current policies*, equipment cost reductions are not significant, but installation cost increases are lower than the *Global NZE* scenarios.

A first of a kind premium, in addition to the costs shown, will likely apply when coal with CCS is deployed in Australia for the first time.

4.3.3 Gas combined cycle

GHD (2025) have included negligible real change in gas combined cycle costs for 2025 which is a change compared to real increases the previous two years. During 2026 to 2035 costs are assumed to slowly return to normal. After the return to normal period, because gas combined cycle is classed as a mature technology for projection purposes, its change in capital cost is governed only by assumed increases in land and installation costs for all scenarios. Consistent with the need for greater construction activity the stronger the climate policy ambition, combined cycle gas costs are highest in *Global NZE by 2050.*

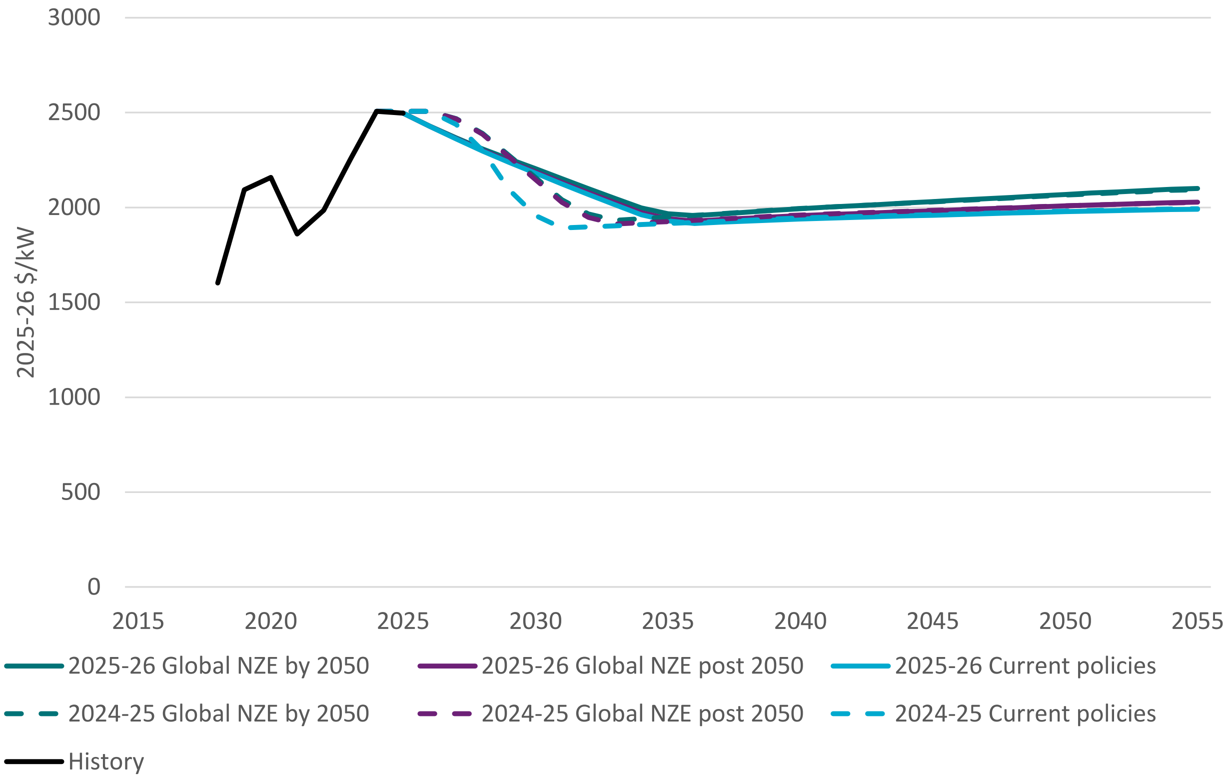


Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2024-25 projections

4.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2025-26 projections and decline to 2035 based on our return to normal assumptions during this period. The relativities between the scenarios reflect the changes in land and installation costs increases and 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. Subsequently, the equipment component of gas with CCS is lower by 2050 in those scenarios and this results in total costs being lower in the late 2030s and early 2040s. In the same period, CCS equipment costs are highest cost where CCS deployment is lowest. However, by 2050, installation costs have increased the most in *Global NZE by 2050* and the least in *Current policies*. The proportionally offsetting sources of cost changes result in a narrow range of costs across all scenarios by 2050.

The IEA CCS database[11] indicates there are over 100 planned electricity related projects which are yet to make a financial investment decision and around 9 under construction. Around 6 are operational. Given the current state of the pipeline of projects, significant global deployment of CCS is not expected until after 2030.

A first of a kind premium, in addition to the costs shown, will likely apply when gas with CCS is deployed in Australia for the first time.

[11] CCUS Projects Database - Data product - IEA

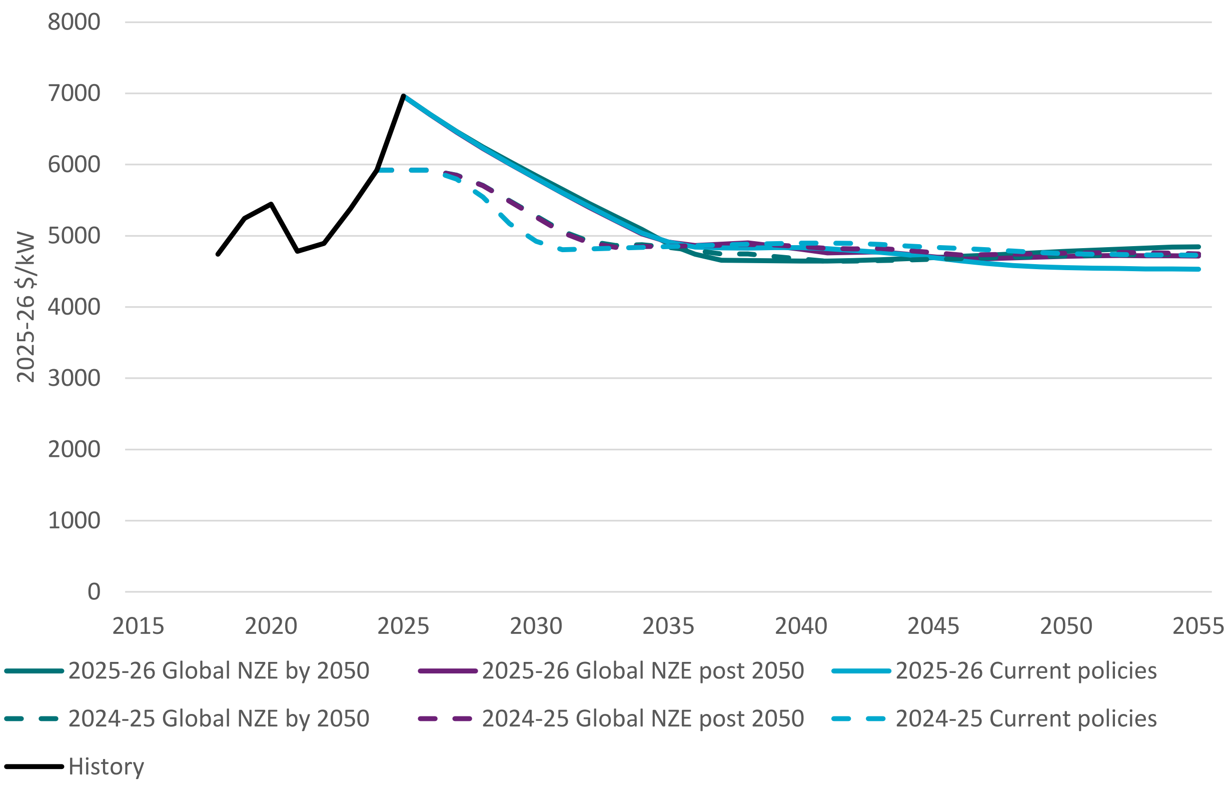


Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2024-25 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2025-26 cost projections for small and large open cycle gas turbines. All new gas turbine projects are expected to include the capability for hydrogen blending and eventual conversion to hydrogen firing when hydrogen supply becomes more readily available and lower cost. This is in addition to the existing ability to use liquid fuels such as diesel or renewable diesel. However, it is possible that some plants will only ever use natural gas during their life. It depends on the market conditions and climate policy during their operation. The small open cycle gas technology is designed with a maximum 35% hydrogen blend. The large size is designed for 10%. However, GHD also provides costs for higher and lower blends at both sizes. This assumption of hydrogen readiness adds a negligible premium to gas open cycle capital costs.

The GHD (2025) report provides additional details for the unit sizes and total plant capacity that defines the small and large sizes. Gas open cycle costs are increasing rapidly due to demand outpacing manufacturing supply capability. Costs are not projected to return to normal until 2035. For the remainder of the projection period, there are no improvements in equipment costs because of the maturity of the technology, and so the assumed land and installation cost increases result in a rising trend in costs. Capital costs are highest under the *Global NZE* scenarios reflecting the higher installation costs associated with the greater construction activity of those scenarios

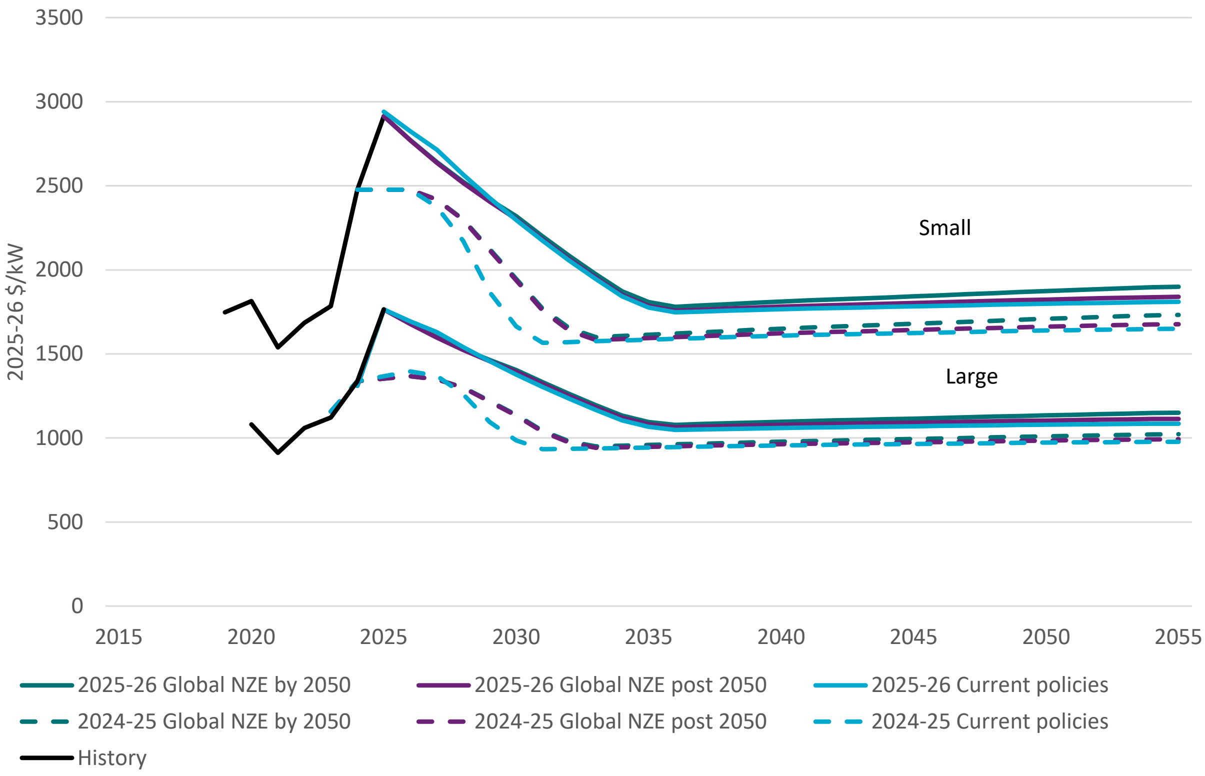


Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2024-25 projections

4.3.6 Nuclear SMR

For the next five years, costs are based on the planned Darlington SMR project in Canada which consists of four 300MW units for a total cost of C$20.9b. Costs are expected to be highest for the first unit but lower for each subsequent unit and this is captured in the cost trajectory. Unlike large-scale nuclear, to convert Darlington nuclear SMR costs to Australian dollars the method only included an exchange rate conversion. That is, no allowance has been made for differences in construction costs between Canada and Australia. The difference in approach is justified based on the high level of commercial immaturity of nuclear SMR outweighing any other uncertainties in the cost estimate.

The rate of cost reductions after the Darlington project is calculated as function of deployment of other global nuclear SMR projects, to a greater or lesser degree depending on the global scenario and some known projects. Capital costs only improve in the 2040s for the *Current policies* scenario due to a lack of additional deployment of projects in the 2030s. The *Global NZE* scenarios achieve a greater level of deployment of nuclear SMR in the 2030s owing to a stronger commitment to addressing climate change.

Nuclear SMR equipment cost reductions may be partly driven by modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. Assumed increases in land and installation costs are responsible for increases in Australian nuclear SMR costs in the 2040s and 2050s.

A first of a kind premium, in addition to the costs shown, will likely apply when nuclear SMR is deployed in Australia for the first time.

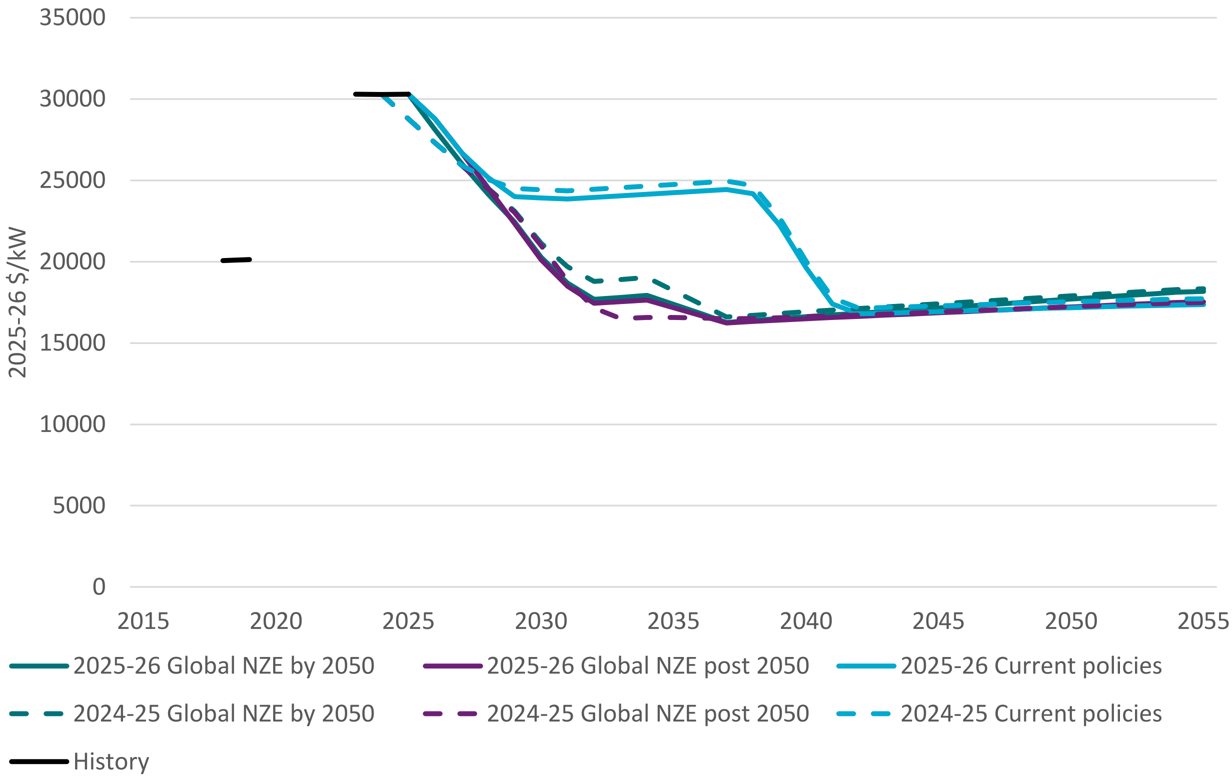


Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2024-25 projections

4.3.7 Large-scale nuclear

Given Australia has no experience building large scale nuclear, we base costs on South Korean nuclear building costs adjusted for the relative costs of building ultra-supercritical coal in each country. Given the cost of building ultra-supercritical coal in Australia has increased, nuclear costs are also revised upwards. From a more direct perspective, given all steam turbine costs have gone up, then nuclear costs are also impacted. However, like other technologies, large-scale nuclear capital costs are assumed to return to their underlying costs by 2035.

Large-scale nuclear is treated as a mature technology and therefore is not assigned any learning rate whereby cost reductions are achieved as a function of deployment. Instead, large-scale nuclear costs increase after 2035 due to the assumed increases in land and installation costs that impact all technologies.

There is some uncertainty in the literature about whether large-scale nuclear is a learning technology or not. There are many new designs for nuclear generation and so it is not a settled technology in the way we might consider steam turbines. Even settled technologies still incrementally change. However, our reluctance to assign a learning rate to large-scale nuclear reflects two issues. First, an assigned learning rate would have little impact because it is difficult for any mature technology to double its global capacity which is the required trigger to achieve an assigned learning rate (see Appendix A for an explanation of the learning rate function). Second, new designs for large-scale nuclear have not always delivered cost reductions. Therefore, our projection reflects a nuclear industry that mostly consolidates construction around proven designs.

A first of a kind premium, in addition to the costs shown, will likely apply when large-scale nuclear is deployed in Australia for the first time.

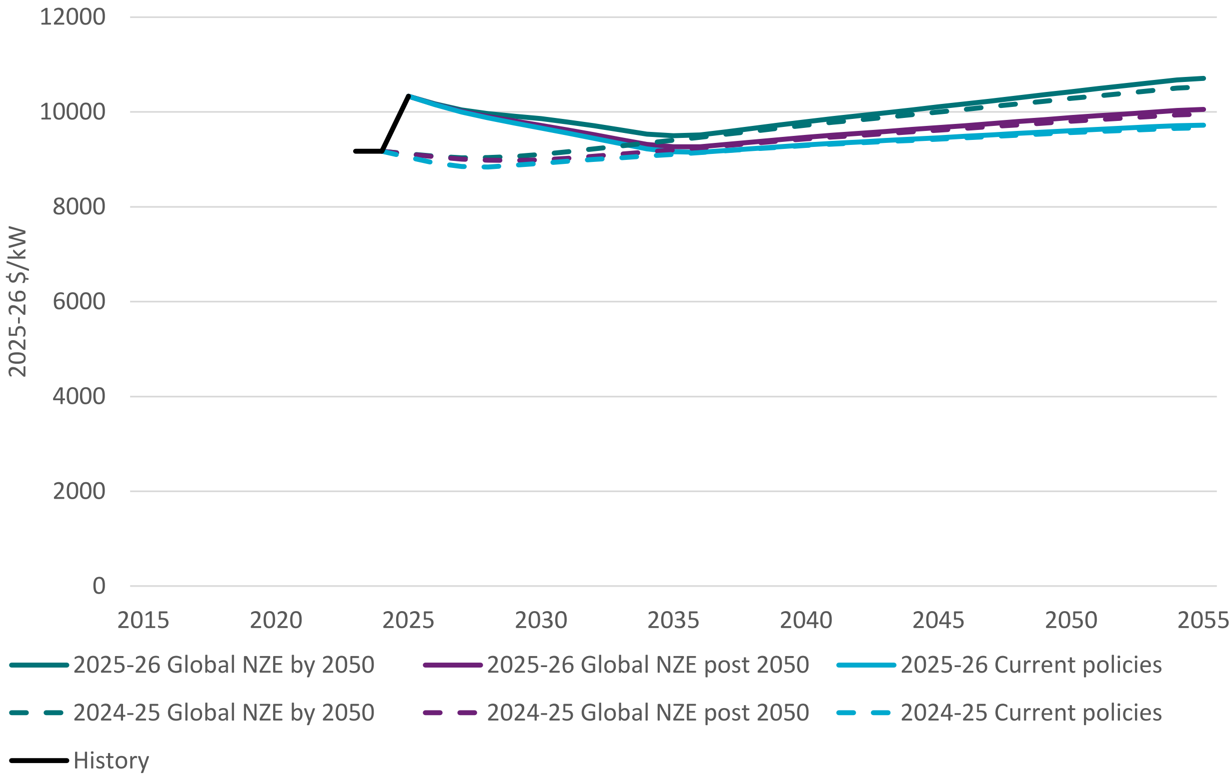


Figure 4-9 Projected capital costs for large-scale nuclear by scenario compared to 2024-25 projections

4.3.8 Solar thermal

The starting cost for solar thermal has been increased by GHD (2025) and this represents the main difference in costs relative to 2024-25. A first of a kind premium, in addition to the costs shown, will likely apply when solar thermal is deployed in Australia for the first time.

Solar thermal systems consist of the combination of solar mirror field, thermal storage and power blocks that are sized in varying ratios according to the location and market signals that prevail. Each such configuration will have a different capital cost. As a consequence, the baseline configuration represented in the capital cost projection data is not the same as the configurations used to calculate the LCOEs in Section 5.

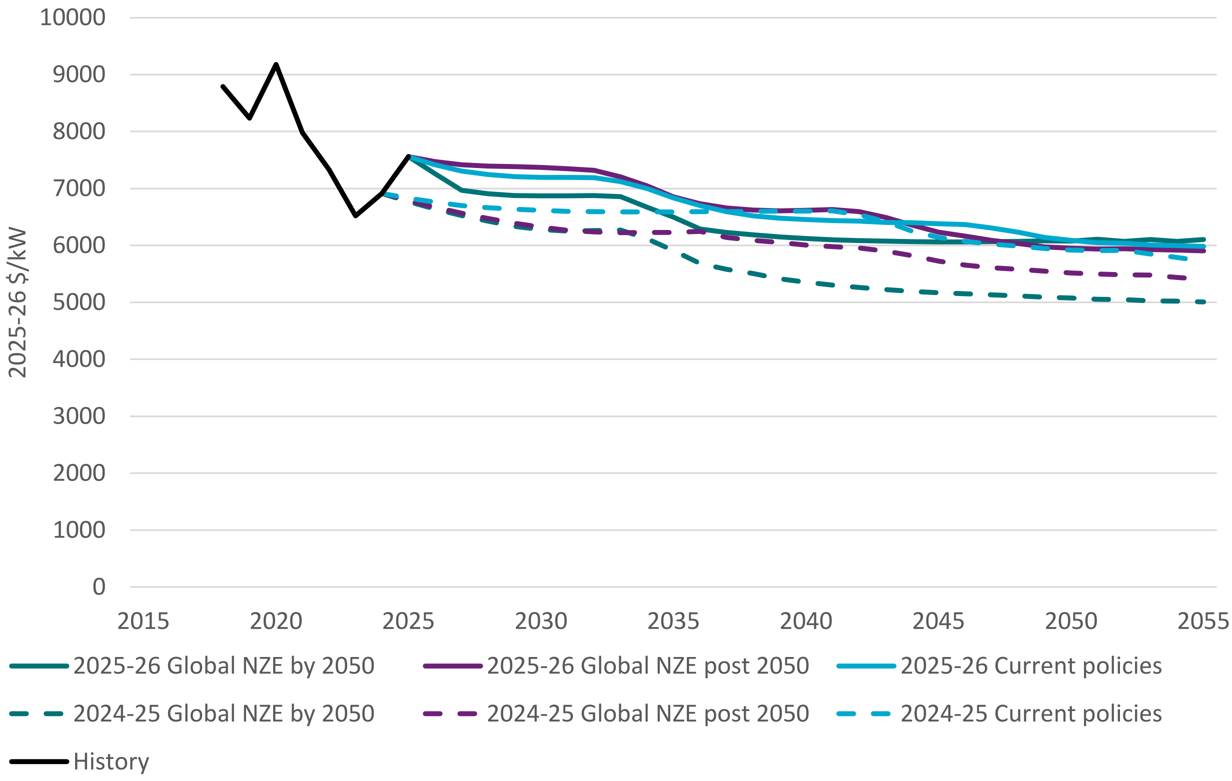


Figure 4-10 Projected capital costs for solar thermal with 16 hours storage compared to 2024-25 projections

4.3.9 Large-scale solar PV

Large-scale solar PV costs have been revised upwards for 2025-26 based on GHD (2025). This represents a reversal of the last two years of gains but likely reflects cost volatility rather than a new trend. As a result of past cost reductions for this technology, unlike other technologies, we do not impose any additional cost reduction related to recovery from the global inflationary pressures. All cost reductions in the projection are due to learning through deployment. *Current policies* has the lowest global share of solar PV generation and therefore the highest cost trajectory. In the *Global NZE* scenarios, there is faster technology deployment to meet stronger climate policies leading to proportionally higher cost reductions. All scenarios include increases in installation costs in Australia and this narrows the differences between the scenarios slightly over time. Installation costs are assumed to grow faster the stronger the global climate policy ambition due to stronger construction activity.

The final minimum cost level for solar PV is difficult to predict because, unlike other technologies, and notwithstanding recent inflationary pressures, the historical learning rate for solar PV has not significantly slowed. The modular nature of solar PV appears to be the main point of difference in explaining this characteristic.

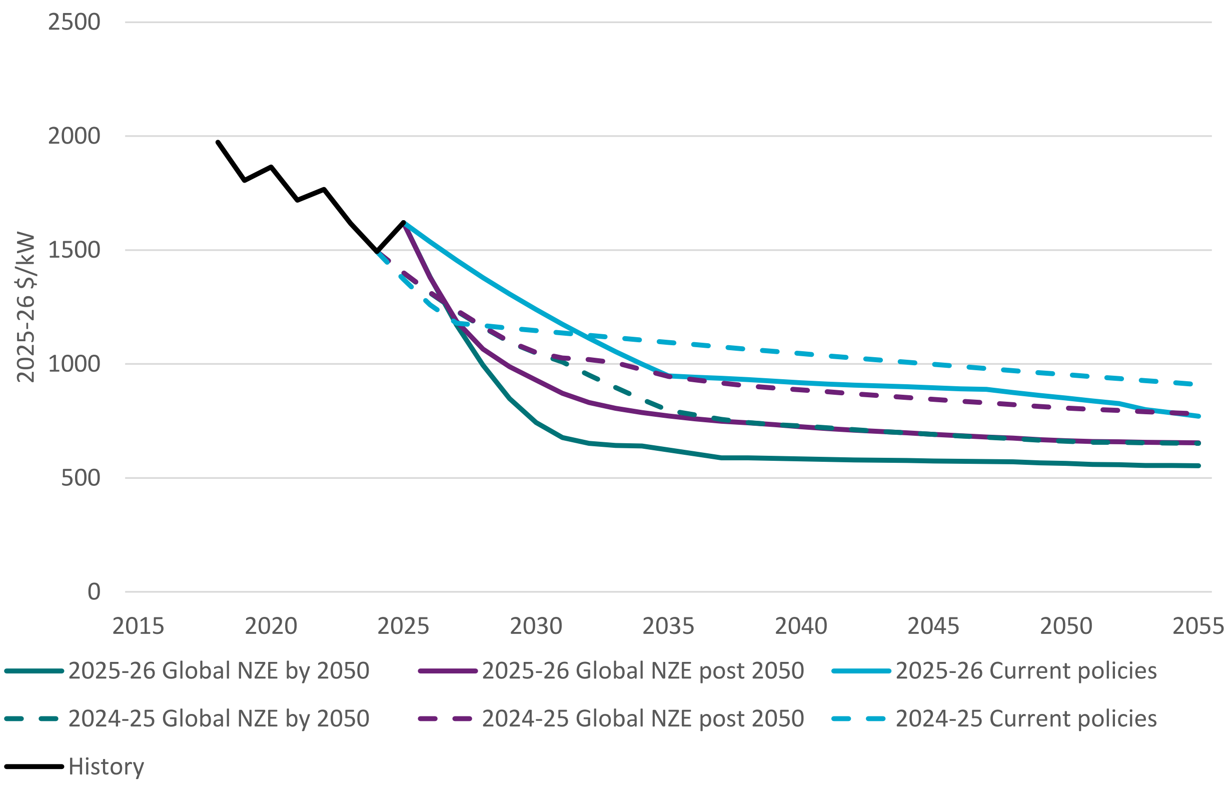


Figure 4-11 Projected capital costs for large-scale solar PV by scenario compared to 2024-25 projections

4.3.10 Rooftop solar PV

The current costs for rooftop solar PV systems are lower than was projected for 2025 in the 2024-25 GenCost report. Rooftop solar PV is sold across a broad range of prices[12] and consequently this data is best interpreted as a mean and may not align with the lowest cost systems available. The cost is before available subsidies and on the basis of the direct current power rating of the system whereas large-scale solar PV and all other generation technologies are on an alternating current power rating basis.

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. However, the rate of capital cost reduction in each scenario is slower than large-scale solar PV because we have assumed a low learning rate on the installation or local learning component for rooftop solar. This reflects that Australia already has a very high degree of experience in installing rooftop solar so there are less opportunities to reduce the cost of installation compared to large-scale solar PV. Installation costs are also impacted by the general increase in installation costs that apply to all technologies.

[12] The Cost of Solar Panels - Solar Panel Price | Solar Choice

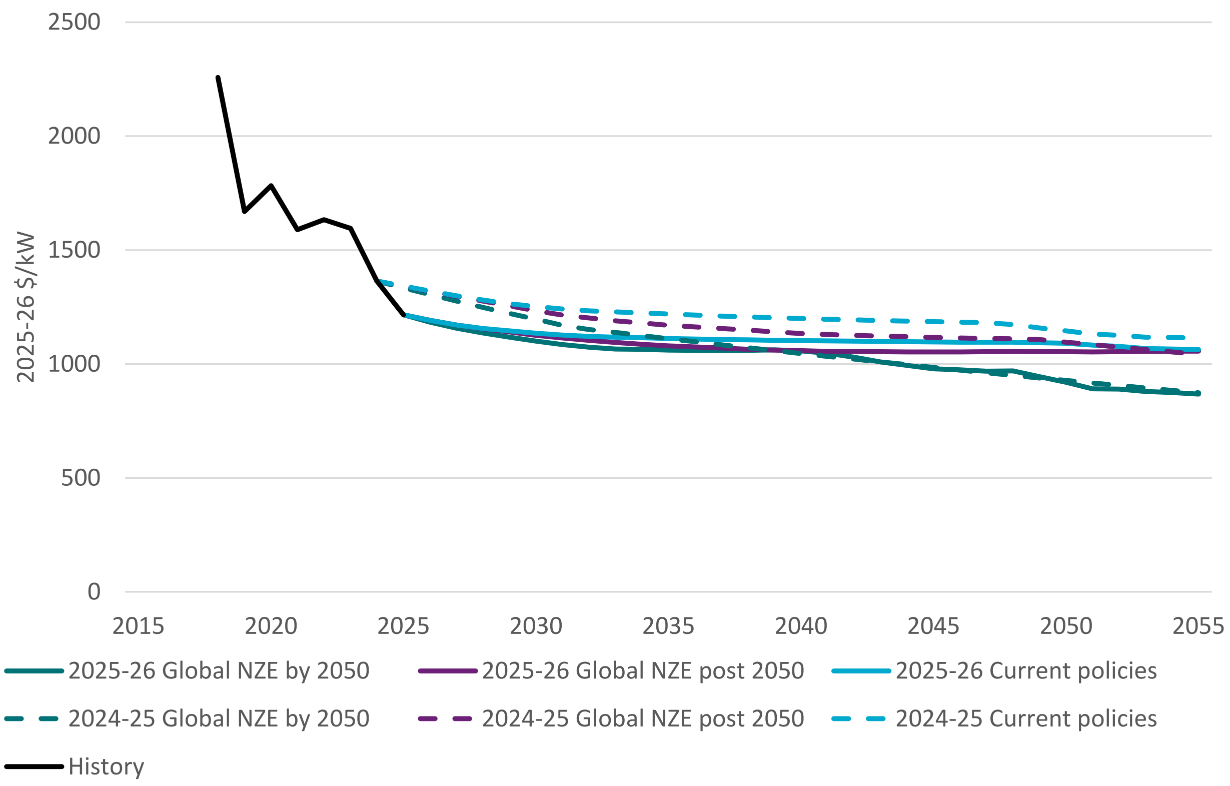


Figure 4-12 Projected capital costs for rooftop solar PV by scenario compared to 2024-25 projections

4.3.11 Onshore wind

As the historical data indicates onshore wind is one of the technologies which has been most impacted by recent global inflationary pressures. The updated GHD (2025) data indicates that the costs pressures are stabilising.

To recognise the more difficult circumstances for the onshore wind industry locally and globally, our assumption is that capital costs of onshore wind will not return to its normal cost path until 2035 in all scenarios. After 2035, wind costs are projected to decline only a modest amount. Global equipment cost reductions from learning are offset by local increases in land and installation costs. While equipment costs fall the most in stronger climate policy ambition scenarios, these scenarios also experience the strongest increase in installation costs due to greater construction activity. Consequently, these global and local changes in costs tend to offset one another resulting in little difference between the three scenarios by 2055.

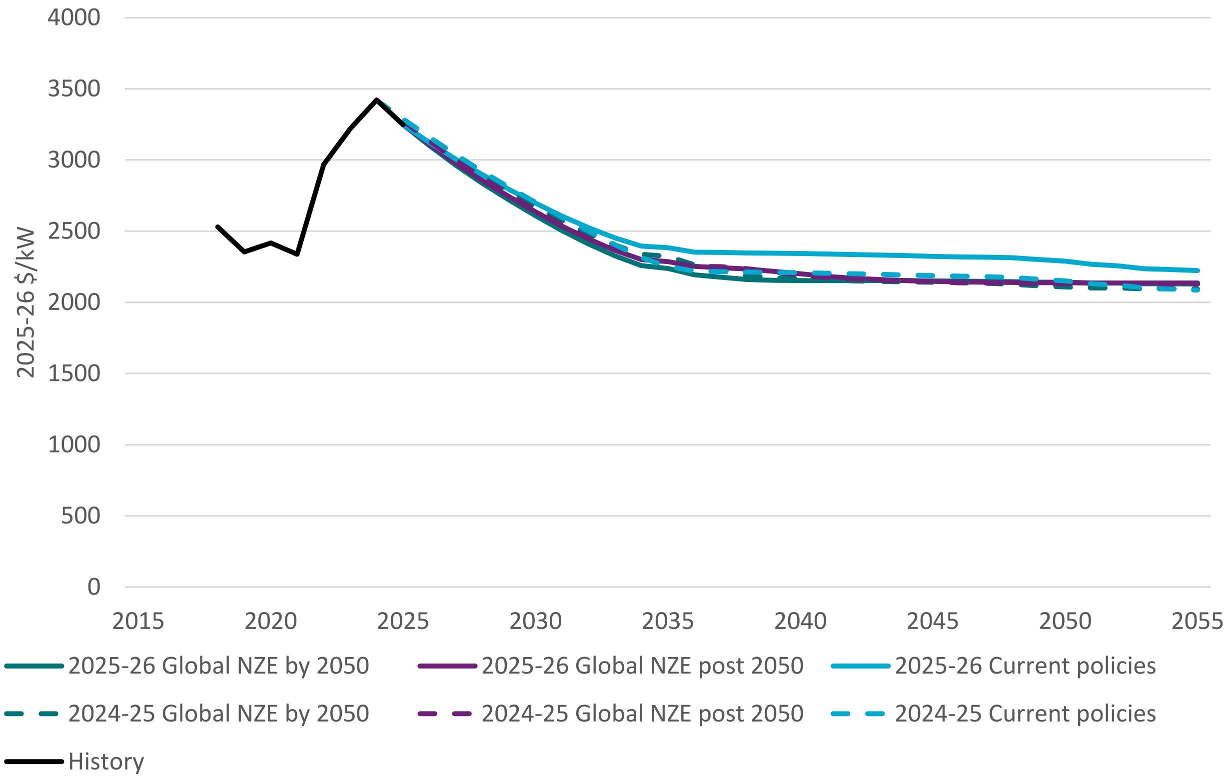


Figure 4-13 Projected capital costs for onshore wind by scenario compared to 2024-25 projections

4.3.12 Fixed and floating offshore wind

Fixed and floating offshore wind are represented separately in the projections. Our general approach is not to include similar technologies because of model size limits and because the model will usually choose only one of two similar technologies to deploy, therefore adding no new insights. However, while the two offshore technologies have a lot of common technology, floating wind is less constrained in terms of the locations in which it can be deployed. As the global effort to reduce greenhouse gas emissions looks increasingly to electricity as an energy source, many countries will be seeking to use technologies that have fewer onshore siting conflicts. Fixed offshore wind is the lowest cost offshore technology, but its maximum deployment is limited by access to seas of a maximum depth of around 50-60 metres[13] and any navigation, marine conservation or aesthetic issues within those zones. Floating offshore wind can be deployed at much greater depths increasing its potential global deployment and providing a unique reason to select the technology.

Figure 4-14 presents projections for both fixed and floating compared to the 2024-25 projection. The current costs for both types of offshore wind are provided in GHD (2025). The updated current capital costs are lower than projected in 2024-25 for floating offshore wind and higher than projected for fixed offshore wind. Post 2025, offshore wind capital costs are not adjusted for inflationary pressures in the same way as other technologies because fixed offshore wind has already recovered based on the average global data which informs the historical series. However,

[13] This is more an economic than absolute technical limit.

it is likely that technology prices are higher for some regions and manufacturers. Australia is not likely to deploy offshore wind before 2030 and therefore GenCost will continue to be required to rely on global sources of offshore wind cost data until then. A first of a kind premium, in addition to the costs shown, will likely apply when offshore wind is deployed in Australia for the first time.

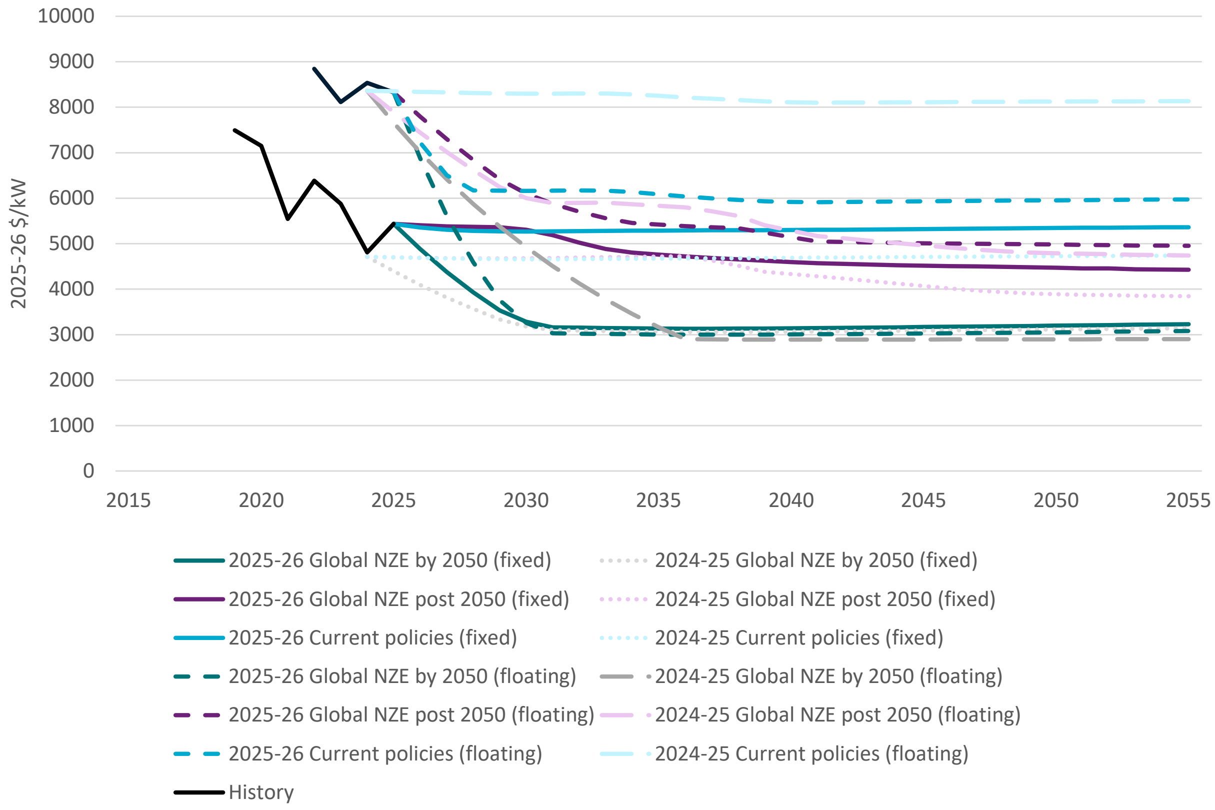


Figure 4-14 Projected capital costs for fixed and floating offshore wind by scenario compared to 2024-25 projections

Floating offshore wind projections are lower relative to the 2024-25 projections and this reflect higher projected global deployment. Fixed offshore wind is higher but this mostly reflects the higher current cost rather than a change in global deployment. Floating offshore wind is deployed more widely than fixed offshore wind and therefore results in proportionally higher cost reductions in the *Global NZE* scenarios.

Offshore wind is not as impacted as other technologies on land costs but does require some onshore land to connect to the grid. Offshore wind costs are impacted by the new assumptions with regards to increasing installation costs.

4.3.13 Battery storage

Current 2025 costs of battery storage fell in line with the fastest cost reduction projected in 2024-25 and the updated cost projections continue to allow for a diversity of outcomes after 2025 ranging from a continuation of the current rate of cost reduction to a slow rate of reduction. The costs shown in Figure 4-15 are for a 2-hour duration battery (total battery cost including battery and balance of plant). Given the 2025 cost reduction takes batteries back to below their pre-pandemic levels we do not impose any additional reduction beyond the learning projected by the modelling.

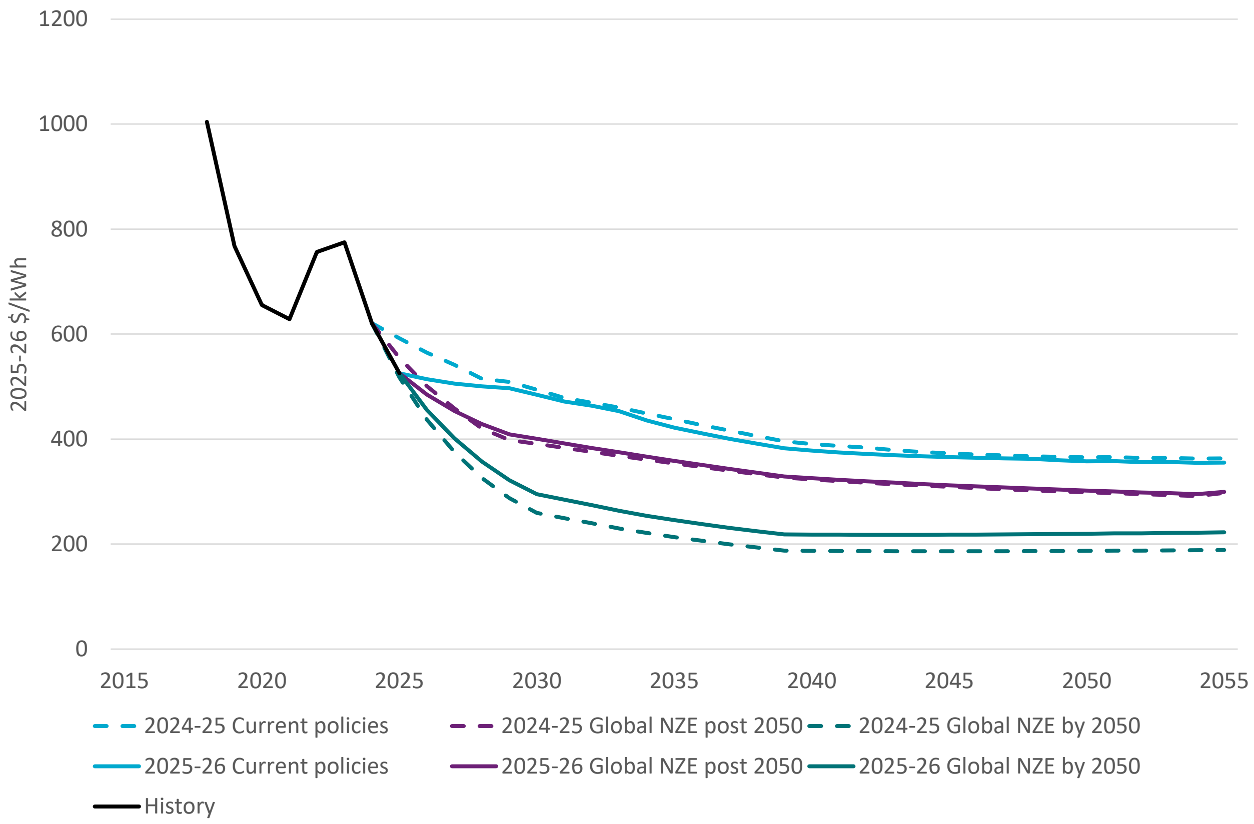


Figure 4-15 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

The projections use different learning rates by scenario to reflect the uncertainty as to whether they will be able to continue to achieve their high historical cost reduction rates (notwithstanding the pandemic period). Historical cost reductions have mainly been achieved through deployment in industries other than electricity such as in consumer electronics and electric vehicles. Global electric vehicle uptake has been updated with inputs from the 2024 IEA World Energy Outlook. While these other uses are important, small- and large-scale stationary electricity system applications are growing globally. Under the three global scenarios, batteries have a large future role to play in supporting variable renewables alongside other storage and flexible generation options and in growing electric vehicle deployment.

Battery deployment is strongest in the *Global NZE by 2050* scenario reflecting stronger deployment of variable renewables, which increases electricity sector storage requirements. Together with an assumed high learning rate this leads to the fastest cost reduction. The remaining scenarios have more moderate cost reductions reflecting a reduced requirement for stationary storage and assumed lower learning rates. All projections are impacted by assumed increases in installation costs. However, for batteries, the learning effects more than offset this factor leading to declining cost trajectories.

A breakdown of battery pack and balance of plant costs for various storage durations are provided in Appendix B.

GHD (2025) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $11,000 for a 5kW/10kWh system or $1100/kWh, including installation but excluding subsidies. This is around twice the cost of large-scale battery projects per kWh.

However, larger household batteries are achieving lower per kWh costs more consistent with large-scale costs.

4.3.14 Pumped hydro energy storage

GHD (2025) has provided a reassessment of pumped hydro energy storage (PHES) costs and this is the main driver of differences in the cost outlook compared to 2024-25. See GHD (2025) for more discussion. PHES is a mature technology and receives the same increase in installation costs as other technologies which is the main driver for the increasing cost trend post 2030. Unlike the other technologies, all three scenarios assume costs return to normal by 2030 (rather than in 2035). This reflects the already large downgrade in costs in 2025. Site variability is also a great source of variation in PHES costs and is separately addressed by GHD (2025) and AEMO external to GenCost.

The cost trajectory shown in Figure 4-16 is for a 24-hour duration storage design. Costs for 10-hour, 48-hour and 160-hour durations are also included in this report (Appendix B).

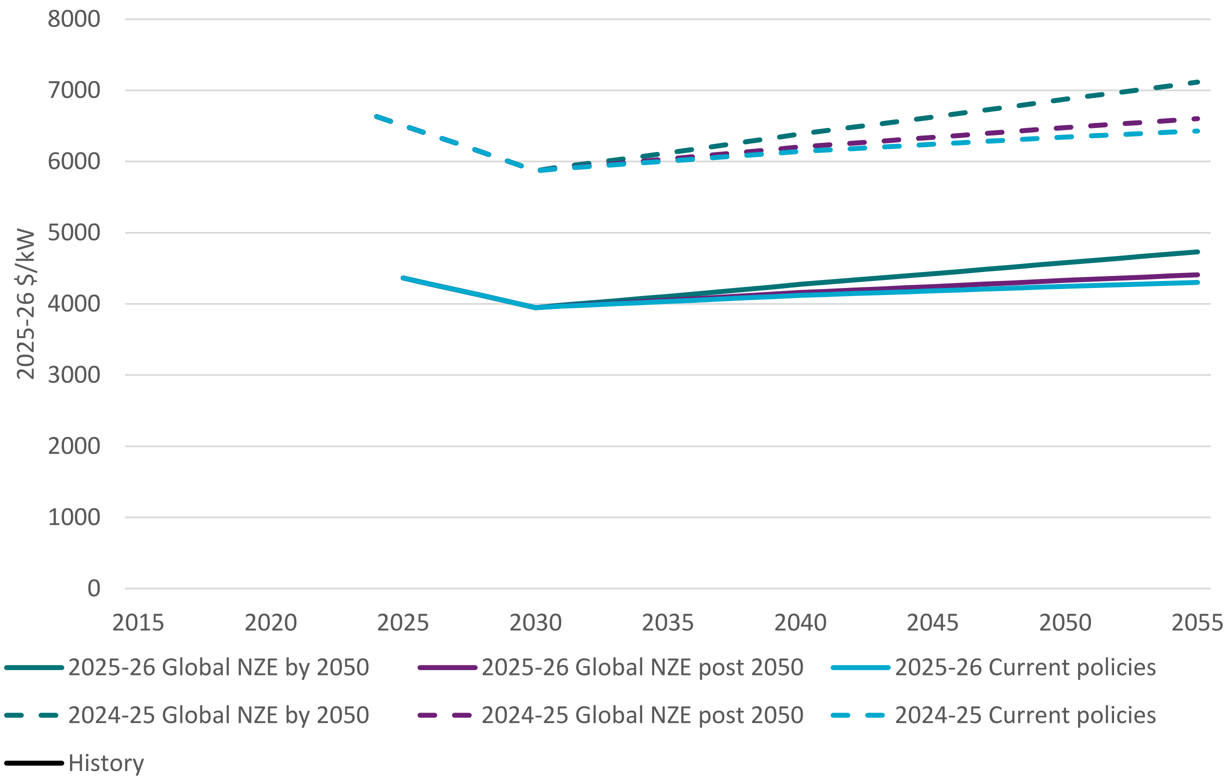


Figure 4-16 Projected capital costs for pumped hydro energy storage (24-hour) by scenario

4.3.15 Other technologies

There are several technologies that are not commonly deployed in Australia but may be important from a global energy resources perspective or as emerging technologies. These additional technologies are included in the projections for completeness and discussed below. They are each influenced by revisions to current costs which have generally experienced an increase in capital costs for 2025 with the exception of fuel cells. Reflecting the infrequency with which these technologies are built, the increases for some technologies mostly represent theoretical increases in costs if they had been built based on the general increase in infrastructure building costs. The downward trend to 2035 has been included using the same methodology for the technologies above. The projections also include increasing land and installation costs for biomass with CCS and fuel cells (wave and tidal/ocean current are excluded due to insufficient data).

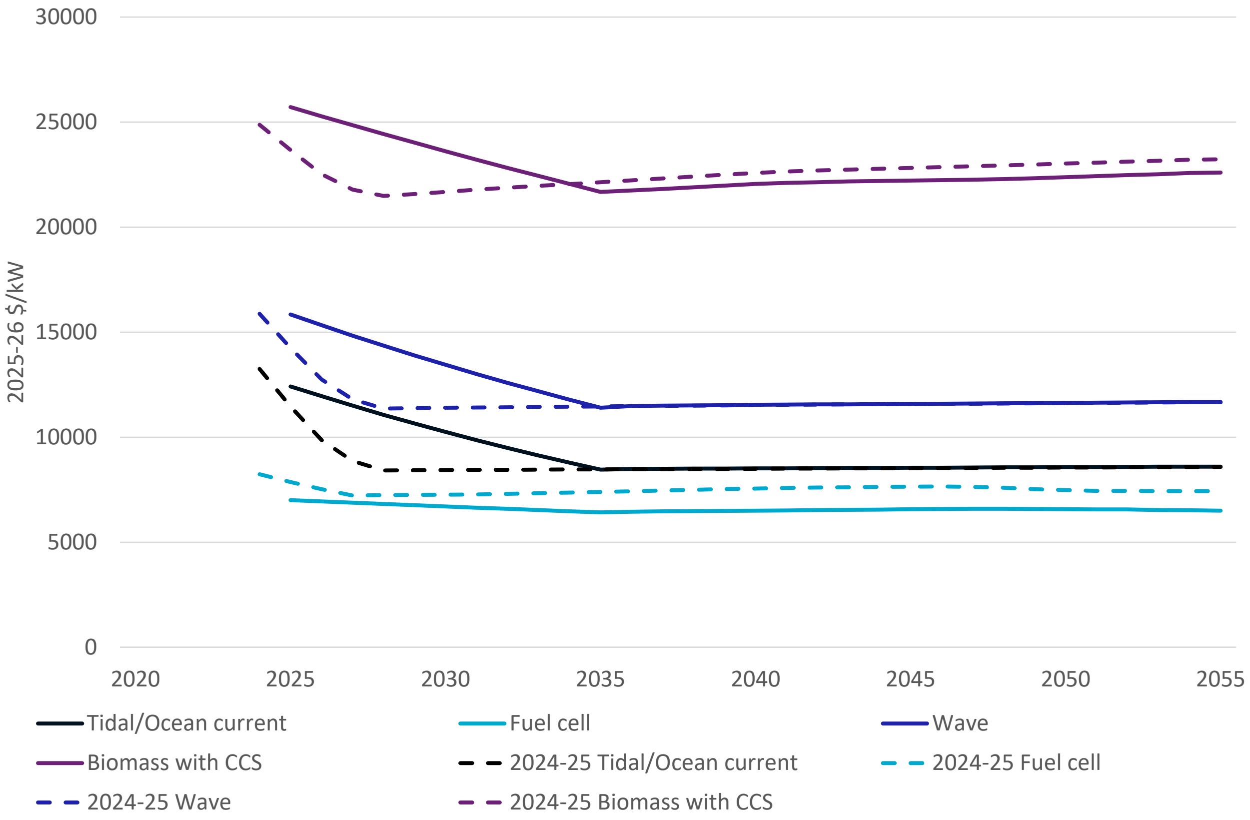


Figure 4-17 Projected technology capital costs under the *Current policies* scenario compared to 2024-25 projections

Current policies

Biomass with CCS is deployed at a negligible level in the *Current policies* scenario because the climate policy ambition is not strong enough to incentivise significant deployment. Cost reductions after 2035 reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors but these are more than offset by increasing installation costs. There is also no significant deployment of fuel cells, tidal or wave technology reflecting the lack of climate policy ambition. Fuel cells are lower owing to updated current costs.

Global NZE by 2050

Biomass with CCS has a low level of adoption in the *Global NZE by 2050* scenario and this is scenario has the strongest increase in installation costs. 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.

Wave energy is deployed at a modest level in the 2040s and tidal/ocean current in the 2050s leading to some costs reductions during those periods. Fuel cells are lower owing to updated current costs.

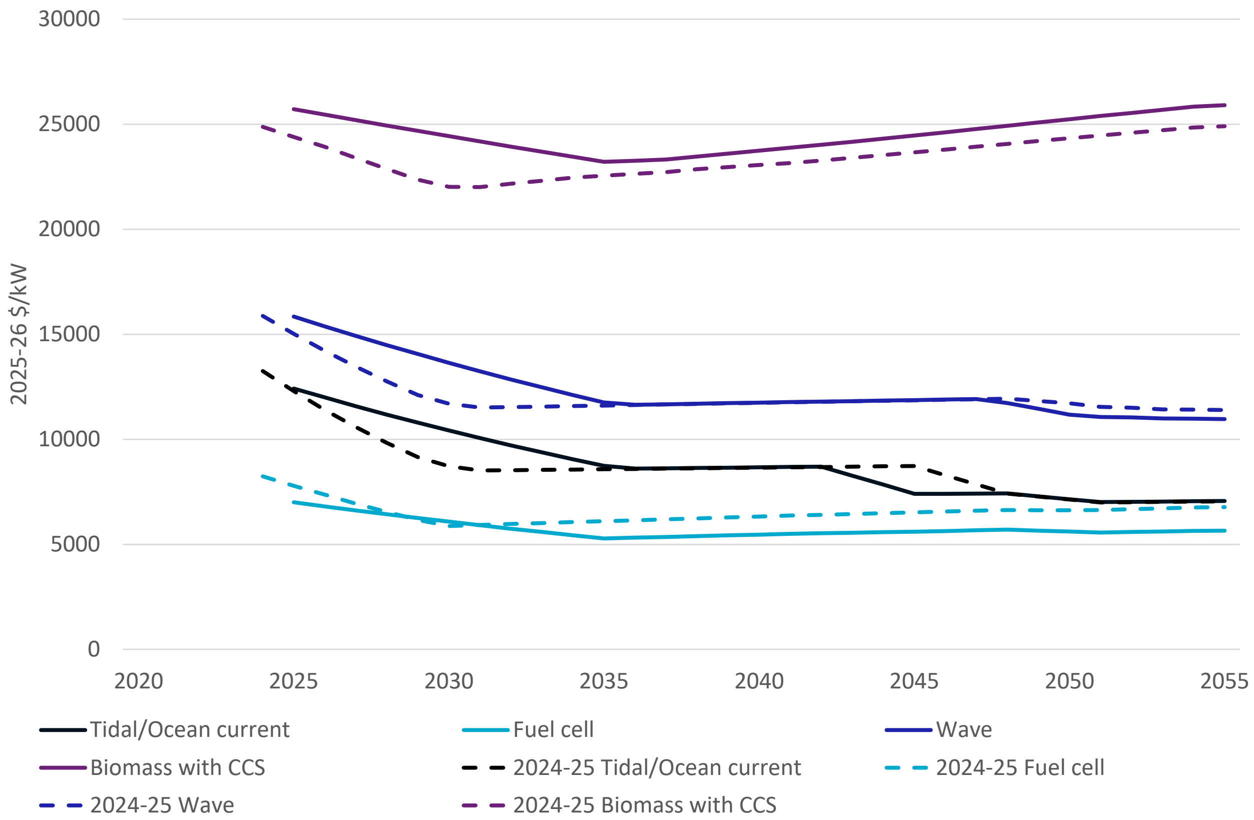


Figure 4-18 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2024-25 projections

Global NZE post 2050

Biomass with CCS is deployed at a slightly higher level than *Global NZE by 2050* resulting in slightly more cost reduction. Both scenarios have significant deployment of steam methane reforming with CCS which brings down the cost of all CCS technologies sooner compared to *Current policies*. There is no significant deployment of other technologies.

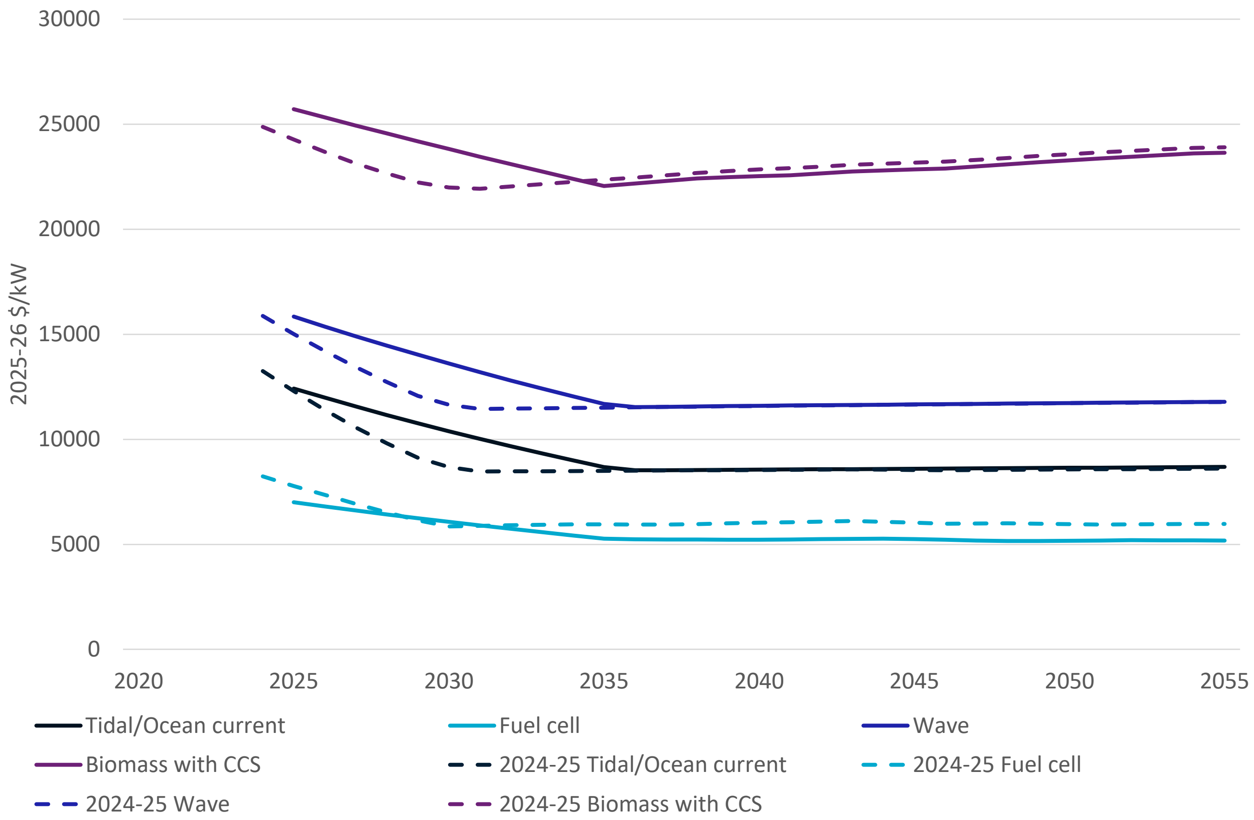


Figure 4-19 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2024-25 projections

4.3.16 Hydrogen electrolysers

Hydrogen electrolyser costs have decreased in 2025 for both proton-exchange membrane (PEM) and alkaline electrolysers based on GHD (2025). Alkaline electrolysers remain lower cost than PEM electrolysers but their costs are becoming closer together.

The key advantage of PEM electrolysers is their wider operating range which gives them a potential 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.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario with the least change expected in *Current policies*.

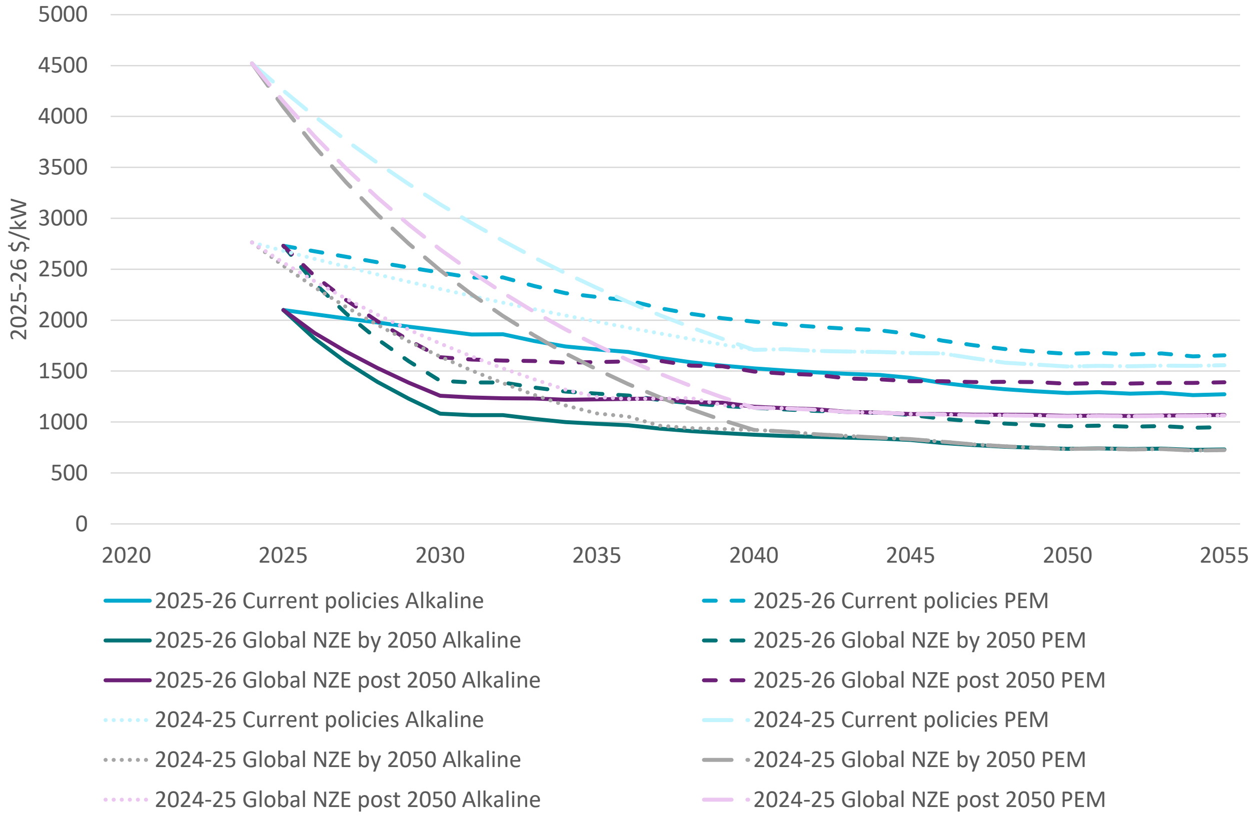


Figure 4-20 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2024-25

5 Levelised cost of electricity analysis

5.1 LCOE definition

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[14]. Modelling studies such as AEMO's Integrated System Plan (AEMO, 2024) do not require or use LCOE data[15]. 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.

The standard method of calculating LCOE does not include all of the additional costs required to deliver reliable electricity supply from variable renewable energy (VRE) generation, particularly when the share of VRE generation is high. The two key VRE technologies are wind and solar photovoltaics (PV). To address this issue of additional VRE costs, since 2019, GenCost has deployed a two-step methodology which separately calculates the VRE integration costs in an electricity system model and then adds them back into the standard LCOE for wind and solar photovoltaics. This method was devised after a thorough literature review in Graham (2018) but is due for an update.

5.2 Change in method for estimating the cost of reliable high VRE share generation

This 2025-26 GenCost report revises the methodology for estimating the cost of high VRE electricity systems in response to stakeholder feedback. Through various submissions over several years, stakeholders requested that the methodology be revised in two ways:

1. Use a System Levelised Cost of Electricity (SLCOE) approach. A SLCOE takes the cost of electricity directly from an electricity system model by dividing all system costs from multiple existing and new technology deployments by the total useful electricity supply in a given year. This concept is also equivalent to the average annual unit cost of electricity for a given electricity system boundary[16]. Calculation of SLCOE is more direct than the previous approach which required setting up a baseline and identifying additional integration costs by calculating differences in costs for alternative levels of VRE generation share. Another advantage is that SLCOE also provides a system perspective which inherently requires a

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[14] For a description the LCOE formula and the application of the formula go to CSIRO's Data Access Portal and download the latest Excel file that accompanies this report. CSIRO Data Access Portal

[15] 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.

[16] In this case we are concerned with generation and transmission

bundle of technologies. This is a more useful perspective than comparing single technologies against one another using LCOE since very few systems use a single technology (the exception being remote power systems but even these are increasingly combining multiple technologies.)

2. Provide greater transparency with regard to the data inputs and the modelling system used.

Separate from these two key items of stakeholder feedback, it was also observed over several years that while public interest in the future generation mix remains high, and the GenCost project's primary goal is to support electricity system modelling by providing cost data, the amount of published electricity system modelling had not increased. It is hypothesised that the high complexity and cost of creating and applying commercial electricity system modelling tools may have been a significant contributor to this outcome. With this context, and to address all three issues simultaneously, a new open source electricity system model was created to calculate SLCOE, replacing the previous method for estimating the integration costs for solar PV and wind.

The new electricity system model is a simplified version of the larger commercial models used by CSIRO and other organisations. With the needs of other potential users in mind, the model was designed to be as short and fast solving as possible whilst not significantly reducing accuracy regarding the estimation of electricity costs and the generation mix. The final model design and the simplifications considered in the development phase are described in Graham et al. (2025). The model is of the National Electricity Market (NEM), excluding Western Australia and Northern Territory. The exclusion of these regions is a simplification in itself but also reflects the fact that these jurisdictions do not provide enough publicly available information about their electricity systems to easily construct an open source model.

Additional model details, software code and all input data can be downloaded at https://data.csiro.au/collection/csiro:71289. The model has been named Simple Electricity Model or SEM. Despite the goal of simplification, the model still requires access to and knowledge of specialised software and solvers and is targeted at users with a university level of knowledge who will likely have most success in following the equations and code. This is because universities typically provide education on linear programming across a wide variety of degree courses as well as access to free software and solver licences. Simpler spreadsheet type models or calculations were considered as an alternative but ultimately are not accurate enough to be relied on to estimate system costs due to their inability to consider and optimise all of the available system configurations.

5.3 SLCOE scenarios

Since 2019 GenCost has estimated the cost of integrating VRE at 60% to 90% shares initially for 2030 and then adding the current year more recently. With the new SLCOE method we have taken the opportunity to update the scenarios. The new analysis focusses on the 82% renewable target in 2030[17] and an emissions intensity target range in 2050 that supports achieving the policy of net

[17] https://www.dcceew.gov.au/climate-change/emissions-reduction/net-zero/electricity-and-energy-sector-plan

zero emissions by 2050. These were judged to be the most relevant electricity systems to be costed in Australia's current policy environment. Stakeholders interested in other scenarios can explore them with the open source model.

The estimation of the 2030 SLCOE excludes all new technology deployment other than renewables and their supporting technologies for two reasons. Firstly, the current policy is specifically targeting renewables. Secondly, under normal project development lead times, there is not enough time for any other low emissions technology to contribute to new generation capacity in 2030. High emission technologies are not relevant to achieving current 2030 policy targets. However, even if those policies were ignored, mature high emissions technologies would also be constrained by development lead times.

The 2050 SLCOE considers either mature firmed renewables *only* or mature firm renewables *plus* any of three groups of technologies: floating and fixed offshore wind, coal and gas with carbon capture and storage and large-scale and small modular reactor nuclear. Each additional technology group is modelled separately because they each are assumed to require two first-of-a-kind (FOAK) projects to be built before they can access the standard technology costs. As such each technology group represents three unique scenarios. It would not be advisable to design a scenario where all technologies are built as it would be prohibitively expensive to build FOAK projects for all technologies. After building the two FOAK projects in each of the technology group scenarios the model determines whether to build any more of that technology at the standard cost based on whether additional capacity of that technology contributes to achieving a least cost electricity system.

The 2050 scenarios must meet emission intensity targets of 0tCO_2e/MWh up to 0.20tCO_2e/MWh. On their own these numbers mean little and so Table 5-1 provides more context and scenario names. It is appropriate to explore a range of electricity sector emissions intensity targets because there is no strict policy on the degree to which any sector must decarbonise in a net zero emissions policy world. To minimise greenhouse gas emissions abatement costs, ideally emission reduction takes place in each sector up to the point where no less expensive abatement may be found in any other sectors, including offset sectors such as land use, land use change and forestry. The value of 0.02tCO_2e/MWh is most closely aligned with AEMO's Step Change scenario in 2024 Integrated System Plan (ISP) modelling results, after adjusting for the ISP only reporting direct emissions and GenCost modelling being on a full fuel cycle basis (that is, inclusive of fugitive emissions in coal and gas extraction). Other emissions intensity scenarios serve as minimum and maximum costs, helping to define the range of possible electricity systems costs in 2050.

AEMO currently makes available 13 historical weather years of demand and renewable production data. It is possible to simulate all of these. However, for the sake of brevity and because for reliability purposes sufficient renewables and other supporting technologies must be deployed to deal with the worst weather conditions, all scenarios only use the single most costly weather year. Graham et al. (2025) provides more detail on the distribution of costs across weather years.

Table 5-1 2050 full fuel cycle greenhouse gas emissions intensity target scenarios and their meaning

2050 emissions intensity target scenario	Scenario name	Meaning
0.20tCO_2e/MWh	NoProgressToNetZero	Consistent with achieving the 2030 82% renewables target policy target and holding the emissions intensity constant to 2050. This is not consistent with achieving net zero by 2050 but serves as a reference case cost against which reducing the emissions intensity beyond 2030 can be measured.
0.10tCO_2e/MWh	WeakNetZero	A halving of the 2030 emissions intensity by 2050. Only weakly consistent with the Australia's net zero by 2050 policy, requiring significantly more abatement in non-electricity sectors.
0.05tCO_2e/MWh	ModerateNetZero	A 75% reduction in the 2030 emissions intensity by 2050. In the range of what is required for the electricity sector to meet Australia's net zero by 2050 policy
0.02tCO_2e/MWh	StrongNetZero	The emissions intensity consistent with AEMO's 2024 Integrated System Plan Step Change scenario. Likely to be what is required to meet Australia's net zero by 2050 policy
0tCO_2e/MWh	ZeroEmissions	Completely eliminating emissions from the electricity sector. This likely exceeds what is required to meet Australia's net zero by 2050 policy but serves to define the maximum cost of electricity associated with emissions abatement.

5.4 SLCOE estimates

5.4.1 Data alignment

For this consultation draft, the results below are based on the GenCost 2024-25 final report generation and storage costs and transmission costs from AEMO's Final 2025 Inputs, Assumptions and Scenarios Report. For the final GenCost 2025-26 report the generation and storage costs will be aligned with the costs in that report (i.e. the final 2025-26 cost estimates after consultation).

5.4.2 Interpretation of costs from SLCOE and LCOE

Neither SLCOE or LCOE estimates guarantee a future wholesale electricity generation price outcome. They indicate the breakeven price required for investors to make a return on their portfolio or individual investments respectively. SLCOE is the more accurate indicator of the two because it includes the integration costs and operational requirements of the entire system whereas LCOE does not with the much simpler calculation only including a limited set of standard cost and technical inputs

Neither of these cost estimates guarantee future electricity prices. Changes in electricity prices are also subject to[18]:

- Supply-demand imbalance as a result of too much or too little deployment relative to demand growth and retirements.
- Fuel price and weather volatility.
- The level of competition amongst suppliers.

These additional drivers of price formation can lead to prices significantly lower or higher than the underlying cost of the system and can take many years to correct due to the long lead times for capacity deployment.

Lead times are impacted by many factors such as the maturity of technology, approval and development processes, general uncertainty, the supply contract market and confidence in government policy directions. Construction times also vary significantly between technologies.

Given this background the SLCOE and LCOE data in GenCost are an indicator of the minimum price needed for investors to enter the market of their own accord ignoring any other uncertainties or external influences. However, should current or future electricity prices be much lower or higher than the indicated breakeven SLCOE, this outcome is likely to have been caused by excess or insufficient new capacity in the market whose root causes may span several years.

5.4.3 SLCOE results and the ISP

The SLCOE results will cover some similar ground to the Integrated System Plan (ISP) in that they present a future generation mix for the NEM. Where results differ, GenCost advises that the ISP should be given greater weight. The SLCOE results are based on a simplified electricity model. The results are designed to be reasonably accurate but, by design, are substantially less sophisticated than the multi-model state-of-the-art framework deployed in the ISP.

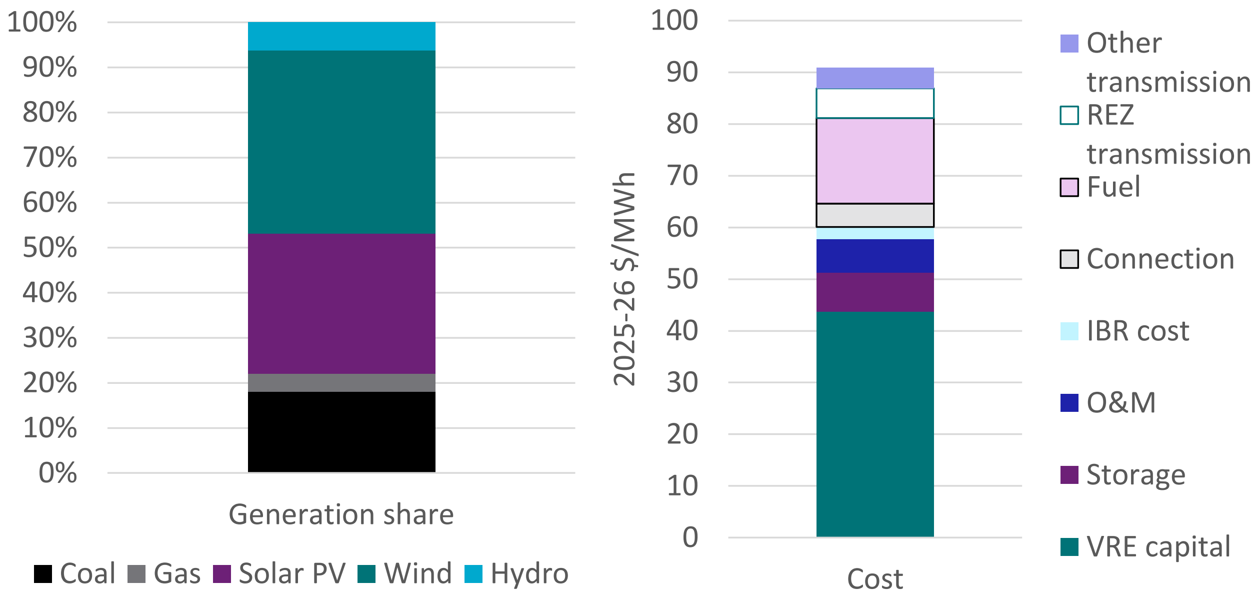
5.4.4 2030 SLCOE results

The 82% renewables by 2030 target includes customer generated electricity (rooftop solar PV). The 2030 modelling takes as given the 2030 rooftop solar PV consistent with the Step Change scenario published by AEMO in their 2025 final Inputs and Assumptions Workbook (the

[18] Retailers also have hedging costs, market fees and ancillary services costs associated with their purchase of wholesale electricity. However, we do not go into those topics here as we are focussed with the main underlying drivers of generation price changes.

Workbook). This reduces the renewable generation share that must be met by large scale generation to around 65% (or 78% when considered as a share of large-scale generation only). The SLCOE for 2030 is the average system cost to meet this large scale generation sector target. The least-cost share of generation sources selected by the modelling is shown on the left-hand-side of Figure 5-1.

The model may use, without any new capital cost, any existing or committed generation capacity as listed in the same AEMO Workbook. Otherwise, it must build new renewable generation, storage, transmission and incur any other cost required to meet the target such as connection costs and ongoing fuel and operating and maintenance costs for existing and new generation capacity. These other costs are sourced from either GenCost or the Workbook. The individual cost components and their contribution to SLCOE are shown on the right hand side of Figure 5-1. The SLCOE in 2030 is $91/MWh in the NEM inclusive of new transmission or $81/MWh for the generation sector only costs[19]. For context, the AEMC (2025) projected wholesale generation costs of just over $90/MWh in 2030, however, this included hedging costs which is a premium paid to avoid exposure to possible higher prices.



VRE-– variable renewable generation; IBR - Inverter-based resources cost such as deployment of synchronous condensers and grid-forming batteries; REZ – renewable energy zone. O&M – operating and maintenance costs

Figure 5-1 The projected 2030 large-scale generation share (left) and SLCOE by cost component (right) consistent with the 82% renewables by 2030 policy

New wind and solar PV capital costs are the bulk of new costs. The next highest cost category is fuel for existing coal and gas generation. Total transmission costs for connecting to renewable zones and other network strengthening are the next largest category followed by storage.

[19] This is a point estimate using the mid range scenarios of fuel and technology cost projections available across GenCost and AEMO's Input and Assumptions Workbook.

Connection costs and inverter-based resources costs associated with maintaining system inertia are the smallest categories[20].

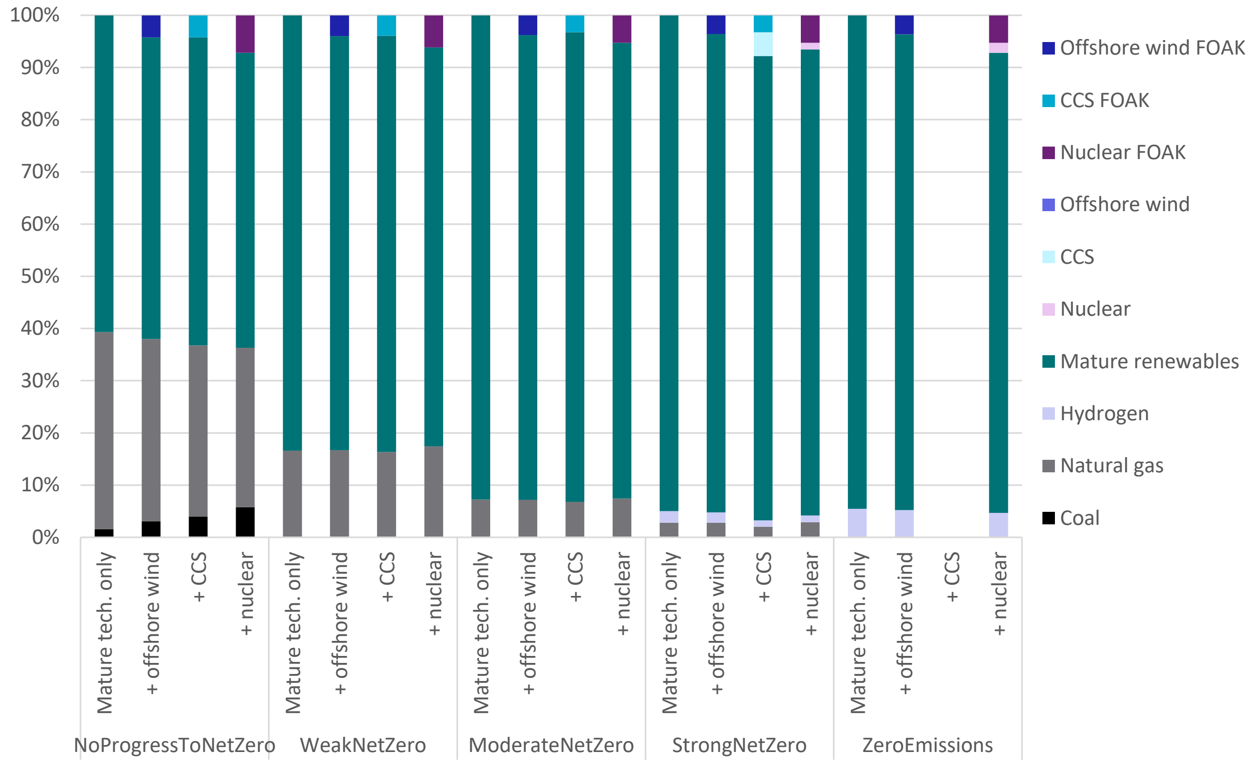
5.4.5 2050 SLCOE results

By 2050, we assume all current generation is retired and only currently existing or committed hydro, pumped hydro and transmission remains. Rooftop solar PV, home batteries and vehicle-to-grid batteries are aligned to the Step Change scenario. In contrast to the 2030 SLCOE, it is assumed that in 2050 there is time available to deploy non-mature low emission technologies to assist in meeting the net zero by 2050 policy.

The three technology groups considered in the analysis are floating and fixed offshore wind, carbon capture and storage (CCS) applied to either coal or gas generation and large-scale and small modular reactor nuclear. However, to be eligible to deploy these technologies at the costs published in Appendix B of this report, each of these three technologies must first build a minimum of two projects at a cost premium consistent with the discussion of first-of-a-kind premiums in Section 2 of this report. The premiums applied are consistent with those presented in Table 2-1. In other words, there is an initial additional cost which must be paid to establish the required workforce, skills and supply chains when commencing a program of building technologies that Australia have not previously been deployed.

The least cost generation mix in 2050 for each emission intensity target and for either mature technologies only or mature technologies plus one of three technology groups not previously deployed in Australia are shown in Figure 5-2. In *NoProgressToNetZero*, with an emissions intensity 0.20tCO_2e/MWh, the 2050 technology mix would retain a significant amount of natural gas and only build new coal when the renewable share has less onshore wind and solar PV. This occurs in the scenarios where FOAK offshore wind, CCS and nuclear projects are required to be built. The modelling chooses not to take up any additional offshore wind, CCS or nuclear beyond the required initial FOAK projects.

[20] Previous versions of GenCost were also able to split out the costs associated with spillage (the loss of capacity factor when renewables are unable to deliver their generation either due to congestion or lack of demand). However under the SLCOE measure, all costs are calculated against useful generation only (that is excluding spilled generation). Consequently, spillage costs inflate all cost categories rather than appear as their own category.



Mature renewables includes solar PV, onshore wind and hydro. FOAK – first of a kind. CCS – carbon capture and storage.

Figure 5-2 The projected generation mix in 2050 by emissions intensity target and allowed technology.

In *WeakNetZero* (at 0.10tCO_2e/MWh) the gas share of generation is more than halved and there is no expansion of offshore wind, CCS or nuclear beyond the FOAK projects. Solar PV and offshore wind gain all of the market share lost by gas and coal relative to *NoProgressToNetZero*. In *ModerateNetZero* (at 0.05tCO_2e/MWh), the same trend occurs with solar PV and onshore wind replacing natural gas with no competition from other generation sources.

In *StrongNetZero* (at 0.02tCO_2e/MWh) the trend changes. Gas is too emission intensive to continue providing 7% of generation that it did under *ModerateNetZero*. However, gas cannot be cost effectively replaced with only solar PV and onshore wind because this would increase storage costs. Instead, the model deploys an alternative flexible generation technology in the form of hydrogen generation. The model also chooses to deploy additional CCS and nuclear beyond the required initial FOAK projects.

When the emission intensity target is set to zero in *ZeroEmissions*, CCS cannot contribute as GenCost only includes a version of CCS technology with 90% capture which cannot be emission free[21]. When deploying only mature technologies or offshore wind, renewable generation combines with hydrogen generation to deliver the required zero emission outcome. If the FOAK nuclear projects are first deployed, the model chooses to extend nuclear generation from of 5% to 7% of total generation in *ZeroEmissions*.

[21] 100% capture technology is theoretically possible but has additional costs.

The expansion of CCS or nuclear in the *StrongNetZero* and *ZeroEmissions* scenarios does not mean that greater deployment of those technologies is least cost. The reason we see these changes in deployment of technologies is because of the path dependency of transmission choices. When a CCS or nuclear plant is established in one region of the NEM, this changes the topology of the transmission system which can increase the cost of expanding transmission elsewhere due to the difference in the scale and ratio of transmission costs required to access renewables. However, if CCS and nuclear is not first deployed then the transmission system aligns with accessing cost competitive renewables. We need to compare the costs of these different generation and transmission systems to determine what it least cost across the scenarios explored. To this end, the SLCOE results for all scenarios are shown in Figure 5-3.

The SLCOE results for 2050 are all higher cost than in 2030 because whereas the 2030 modelling met demand using a significant amount of existing capacity, the 2050 modelling only allows for existing long lived transmission and hydro technology, assuming all other large scale generation technology that exists today has retired[22]. For this reason, the 2050 estimates overstate the average cost of generation in 2050 by assuming there will be no significant existing generation capacity, but the estimates can be considered an upper bound on average costs[23].

The SLCOE results show that deploying mature technology only (solar PV, wind, gas and storage) is the least cost generation mix in 2050 for all emission intensity levels modelled. For the FOAK technologies, the CCS and offshore wind scenarios have very similar costs with CCS being only slightly lower cost than offshore wind. Nuclear is consistently the highest cost. The gap between mature renewables with gas and storage and the alternative low emission technology options narrows, the lower the emission intensity target. These outcomes are based on average costs. Offshore wind has a much wider cost uncertainty range and so could perform better under alternative cost scenarios not explored.

[22] This is not strictly true because most solar PV built now or in the last few years will remain operating in 2050 due to their 30 year life.

[23] In practice, the partial existing capacity that would normally be available to meet 2050 demand will be developed and paid for through generation in the decades leading up to 2050 and building out this investment pathway is how a more commercial grade electricity system model would estimate electricity costs over time. However, in this simplified modelling approach we only include selected long-lived existing resources and other resources needed to meet demand in 2050 are built in 2050 and paid for in the decades that follow (through amortisation).

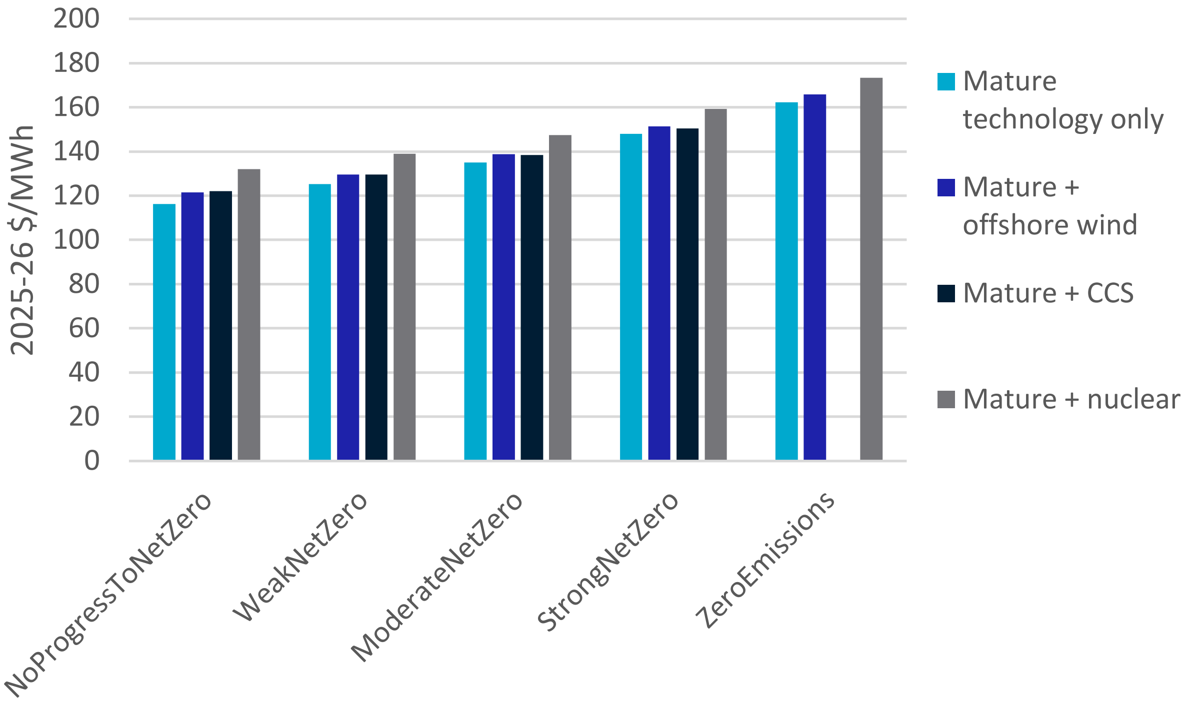
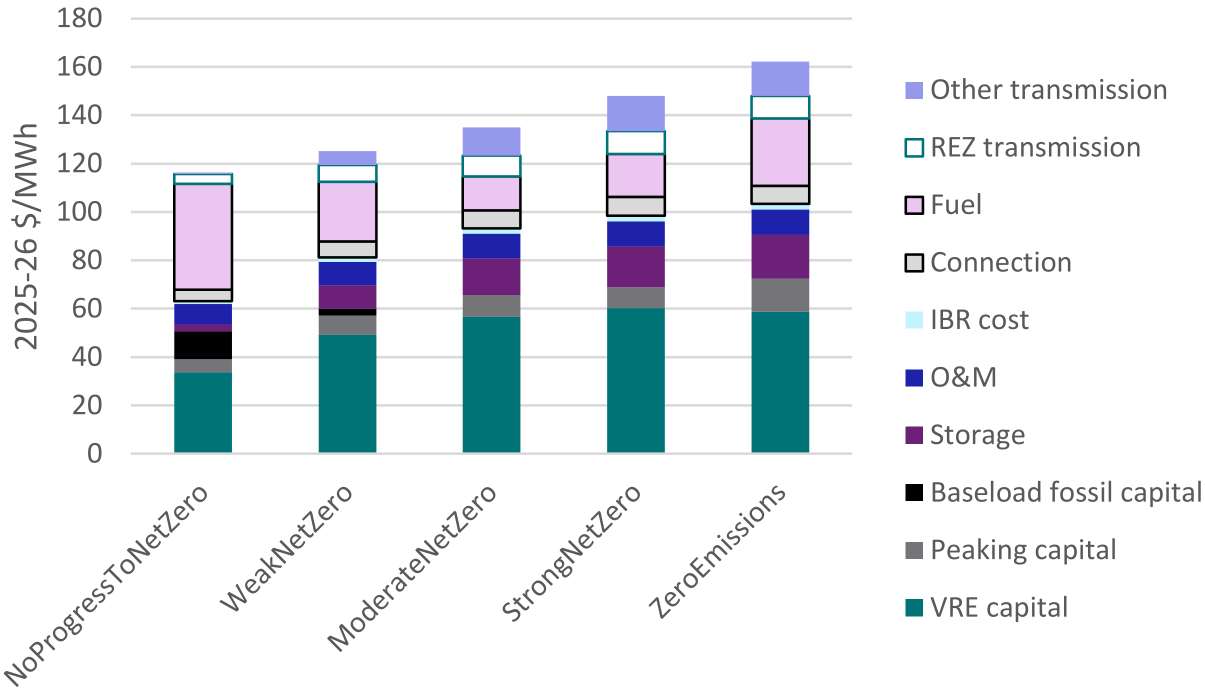


Figure 5-3 The projected SLCOE in 2050 in the NEM by emission intensity target and technology allowed

There is a clear trend that decreasing emissions increases 2050 electricity costs. This reflects that as the emissions intensity declines, more zero emissions technology must be deployed, supported by more storage and more transmission as well as more expensive fuels (such as hydrogen) in some cases (*StrongNetZero* and *ZeroEmissions*).

The breakdown of costs for each emissions intensity scenario is shown in Figure 5-4. The fuel cost falls as the gas share of generation declines but increases for the last two scenarios as hydrogen enters the generation mix with hydrogen fuel being higher cost than gas on an energy unit basis. Baseload fossil fuel costs also fall as they are removed from the generation mix as the emission intensity declines. Almost all other cost categories increase as the emissions intensity falls. However, the increase in connection costs, inverter-based resource costs and operating and maintenance costs are relatively minor. The biggest increases are in storage and transmission costs.



VRE-– variable renewable generation; IBR - Inverter-based resources cost such as deployment of synchronous condensers and grid-forming batteries; REZ – renewable energy zone. O&M – operating and maintenance costs
Figure 5-4 The breakdown of SLCOE in 2050 in the NEM by cost component for mature technology only scenario

As discussed in the scenario descriptions, in theory the highest of the projected costs in 2050 need only be experienced if lower cost abatement is not available elsewhere in the economy outside of the electricity sector since there is no specific requirement for the electricity sector to eliminate all emissions. To shed some light on this issue, the average and marginal (incremental) cost of abatement of each emissions intensity level was calculated relative to *NoProgressToNetZero* (Figure 5-5). This can be compared to the expected cost of abatement across the whole economy to reach net zero which is published by Infrastructure Australia[24]. They publish a cost of abatement range in 2050 of $304 to $497/t$CO_2$e (adjusted to 2025 dollars).

Based on the whole of economy cost of abatement range, it is not economically efficient for the electricity sector to achieve zero emissions. While the average cost of abatement of achieving zero emissions is lower than the whole of economy cost range, this is only because there are low abatement costs for removing the first 90% of those emissions. However, removing the last 10% of emissions is very high costs as indicated by the marginal abatement cost for the *ZeroEmissions* scenario.

The *StrongNetZero* scenario or an emissions intensity level of 0.02tCO_2e/MWh is efficient for achieving net zero if the whole of economy cost of abatement is at the highest range but it inefficient if it is in the lower range. That is, at the low range whole of economy abatement cost it would be more efficient to achieve further abatement outside of the electricity sector. In this case it would be efficient for the electricity sector to target an emissions intensity of 0.05tCO_2e/MWh in

[24] https://www.infrastructureaustralia.gov.au/publications/valuing-emissions-economic-analysis

the *ModerateNetZero* scenario or slightly below that given its marginal cost of abatement is below the whole of economy range.

In summary, examining the cost of abatement indicates that:

- In a whole of economy effort to reach net zero by 2050, the modelling result indicate that it will not be efficient to eliminate all emissions from the electricity sector. It will be more efficient to undertake further abatement elsewhere in the economy
- The efficient range of emissions intensity of the electricity sector lies somewhere between 0.02tCO_2e/MWh to 0.05tCO_2e/MWh depending on the uncertainty in the whole of economy abatement cost.
- Achieving the electricity sector's efficient role in whole of economy net zero abatement is projected to result in electricity costs of between $135/MWh to $148/MWh in the NEM inclusive of new transmission costs or $115/MWh to $124/MWh measured as wholesale generation costs only. For context, in 2024-25, the average NEM volume weighted generation price is estimated to be slightly higher than the top end of this range at $129/MWh.
- Achieving weak or no progress in reducing electricity sector emissions in the period between 2030 and 2050 is not efficient for achieving net zero because electricity sector emissions reduction is substantially lower cost than emissions reduction elsewhere in the economy.

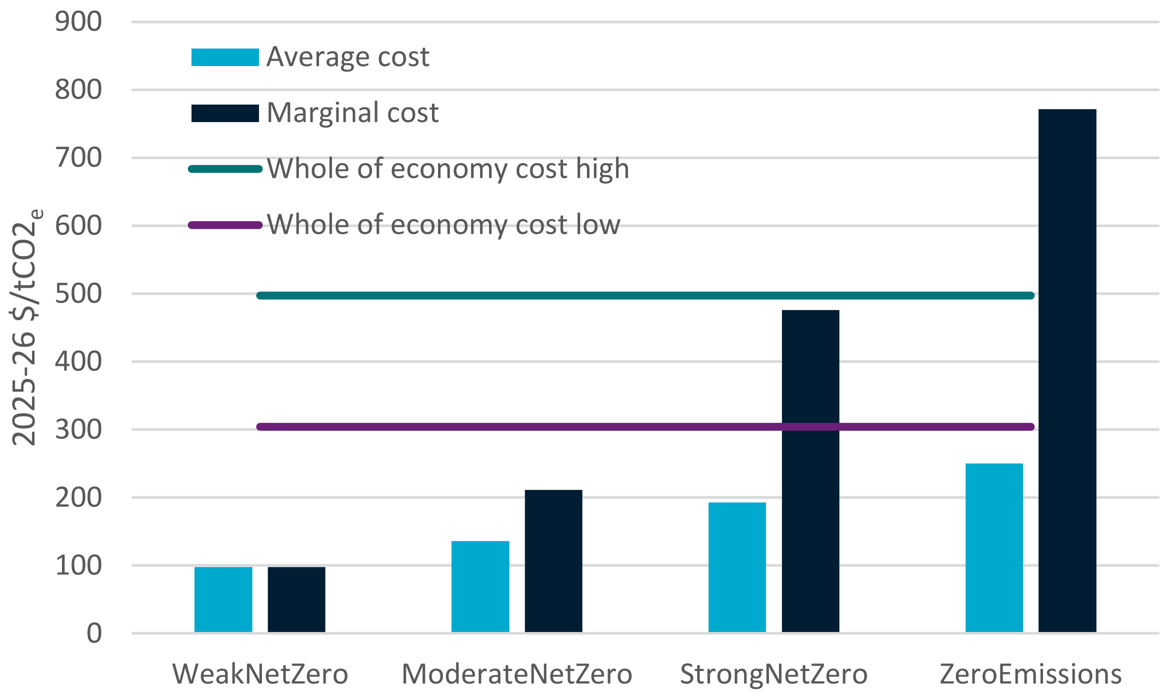


Figure 5-5 Average and marginal cost of abatement to achieve lower emissions intensity targets in 2050 compared to whole of economy abatement costs

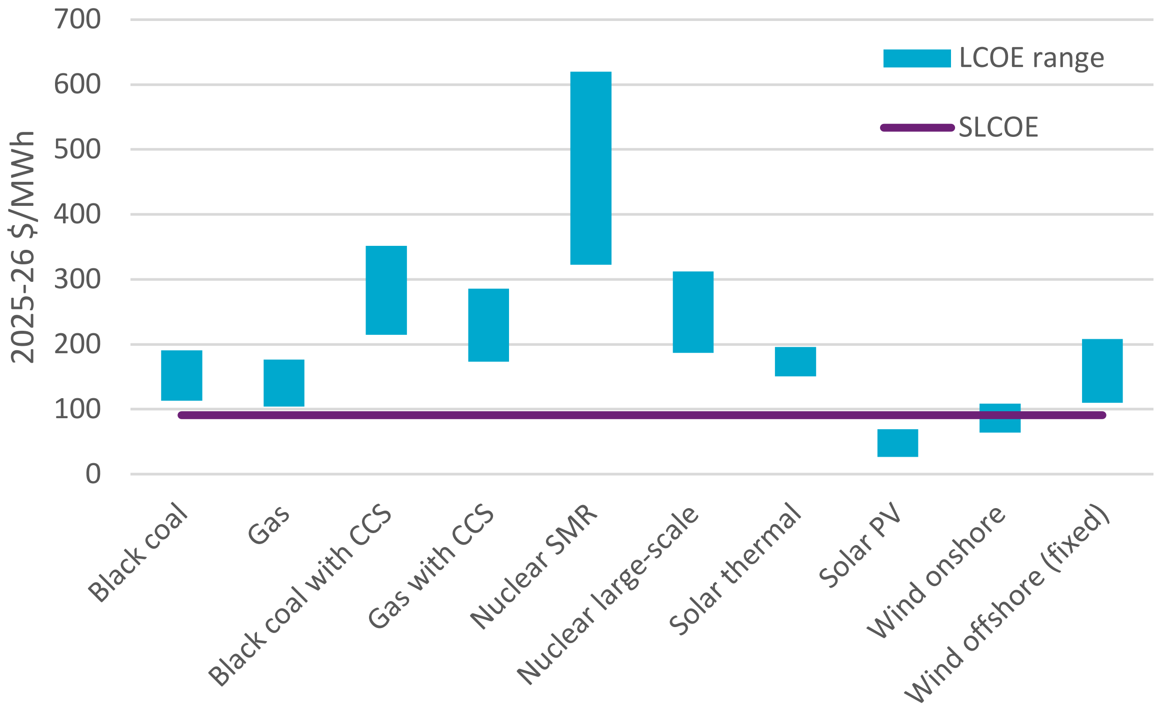
5.4.6 Comparative analysis of cost results

There is a surprising range of estimates of the cost of electricity from systems with a high share of weather dependent renewable generation. These studies have been separately reviewed in Graham (2025) where costs have been estimated in the range of below $70/MWh to over $1000/MWh. The research finds in each case where system average costs were reported to be high, it was observed that the modelling had excluded key resources required to keep costs low. Typical exclusions included: only one type of storage technology allowed, only one duration of storage technology allowed, peaking technology not allowed and a narrow set or single type of renewable generation allowed. When resources are made available, renewable generation is lowest cost when sourced from both solar PV and wind in different locations and combined with multiple storage technologies and gas or hydrogen peaking plant. Graham (2025) concludes that the observed exclusions do not appear to be valid for the NEM which has all of these resources available.

5.5 LCOE estimates

In addition to the SLCOE estimates provided in the previous section, the LCOE for individual technologies is also calculated and represents the breakeven price needed for each technology to achieve a reasonable return on investment. Appendix B includes the LCOE for additional years and technologies, however in this section we focus on a selected set of technologies for consistency with the SLCOE modelling.

Figure 5-6 shows the LCOE results for 2030 and the estimated SLCOE for 2030 is added for context. As discussed in the SLCOE section, given normal development lead times, there is insufficient time before 2030 to deploy technologies other than those already in the development pipeline which consists primarily of solar PV, wind, gas and storage (batteries and pumped hydro). However, the LCOE data indicates that were it possible to develop other technologies they are not expected to breakeven under the 2030 electricity system if wholesale electricity prices are close to the estimated SLCOE. CCS, nuclear, solar thermal and offshore wind are above the estimated 2030 SLCOE.

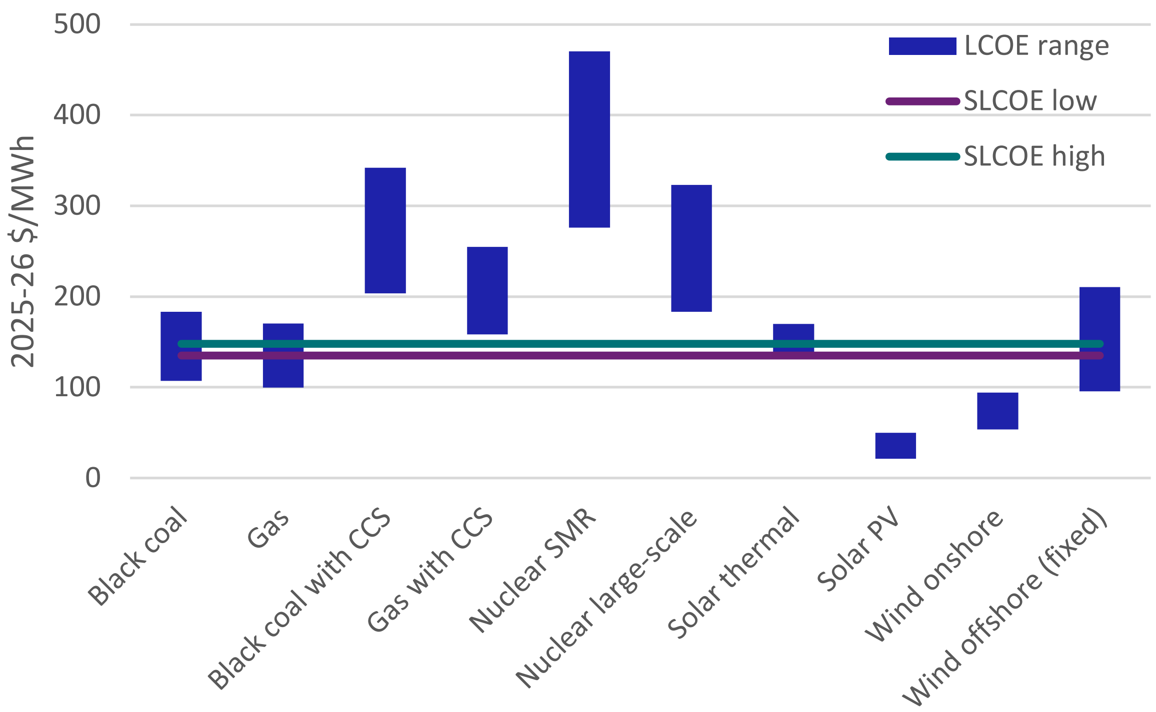


LCOE excludes integration costs. SLCOE includes integration costs of the least cost technology mix
Figure 5-6 Calculated LCOE range by technology and SLCOE for 2030

Figure 5-7 shows the LCOE results for 2050. Here they have been compared to the electricity system cost range identified in the SLCOE analysis as being the efficient range for the electricity sector to contribute to achieving net zero. By 2050, the costs of most technologies other than coal and gas have fallen. Solar PV and onshore wind (without integration costs) are lowest cost relative to the SLCOE estimates. The SLCOE analysis, which does include the renewable integration costs, indicates that solar PV and wind will deliver the majority of electricity supply supported by storage, transmission and either gas or hydrogen or a combination of both.

New black coal, while competitive at this SLCOE range is not relevant for deployment since electricity system modelling shows it cannot efficiently contribute to achieving net zero (that is, it would increase the cost of achieving net zero across the economy). New gas is also in the competitive range and unlike coal, the SLCOE analysis indicates it will play a role in achieving net zero emissions contributing a 3% to 7% share of generation.

Solar thermal is competitive relative to other technologies and inside the SLCOE range. However, given the need to access better solar resources which are further from load centres, solar thermal will be subject to additional transmission costs compared to coal, gas and nuclear which have not been directly accounted for. Based on previous GenCost analysis for solar PV and wind, additional transmission costs could add around $10-20/MWh. Some offshore wind is also in the competitive range however the modelling used the average cost of offshore wind. Lower range offshore wind costs appear to be competitive but were not explored in the modelling and so need more analysis.



LCOE excludes integration costs. SLCOE includes integration costs of the least cost technology mix
Figure 5-7 Calculated LCOE range by technology and SLCOE range for 2050

Gas with CCS is the next most competitive after solar thermal and offshore wind. Large-scale nuclear is slightly higher in cost than gas with CCS. Black coal with CCS occupies a similar cost range to nuclear. Nuclear small modular reactors (SMRs) are the highest cost. Achieving the lower end of the nuclear SMR range requires that SMR is deployed globally in large enough capacity to bring down costs available to Australia. Lowest cost gas with CCS is subject to accessing gas supply at the lower end of the range assumed (see Appendix B for fuel cost assumptions). Coal, gas and nuclear technologies would all have to be successful in operating at 89% capacity factor[25] to achieve the lower end of the cost range when historically coal, which has been the main baseload energy source in Australia's largest states, has only achieved an average of around 60%.

[25] The lowest cost flexible plant in the system will typically be able to operate at this high capacity factor. However, this will be challenging for new plant to achieve. Older existing plant, with their capital costs mostly paid down and access to existing low cost fuel sources, are typically the lowest cost generation units. New generation units entering the market must recover their capital costs and tend to have less favourable fuel contracts due to competition with export markets.

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 publications (Hayward and Graham, 2017; Hayward and Graham, 2013; Hayward, Foster, Graham and 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 and Schrattenholzer, 2001). Cost reductions due to this phenomenon are normally shown via the equation:

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

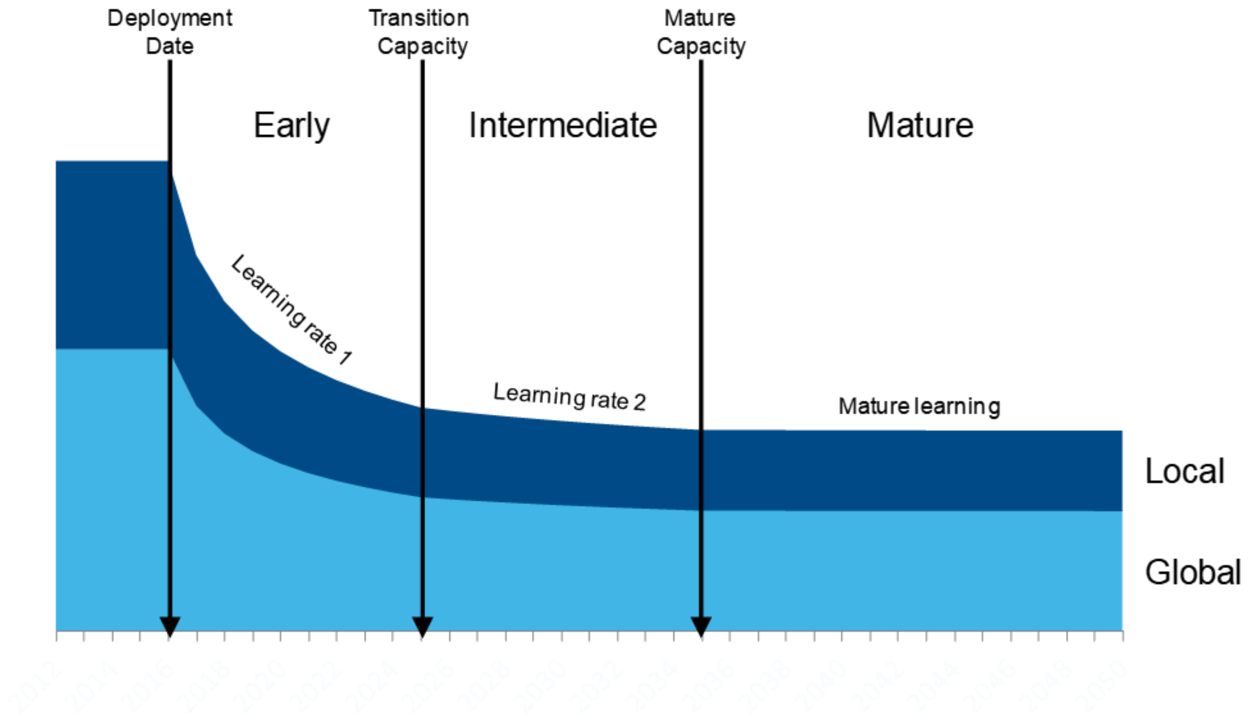
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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 states 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% (McDonald and Schrattenholzer, 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 are modular and as a result 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, batteries 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 the relative cost reductions given each region will have a different level of demand for a technology.

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 and Graham (2013) and Hayward et al. (2017) for more information. Both models run from the year 2006 to 2100. However, results are only reported from the present year to 2055.

A.1.3 Offshore wind

Offshore wind has been divided into fixed and floating foundation technologies. IRENA (2024) and Stehly and Duffy (2021) provided a breakdown of the cost of all components of both fixed and floating offshore wind, which allowed us to separate out the cost of the foundations from the remainder of the cost components. This division in costs was then applied to the current Australian costs from GHD (2025) resulting in the values as shown in Apx Table A.1.

Apx Table A.1 Cost breakdown of offshore wind

Cost component	Fixed offshore wind ($/kW)	Floating offshore wind ($/kW)
Foundation	597	2393
Remainder of cost	4065	4065
Total cost	4662	6459

The learning of all offshore wind components (i.e., “Remainder of cost” components) except for the foundations are shared among both offshore wind technologies. The floating foundations used in floating offshore wind have a learning rate, but the fixed foundations used in fixed offshore wind have no learning rate.

Appendix B Data tables

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

The year 2025 is mostly sourced from GHD (2025) and is aligned to July which represents either the middle of that calendar year or the beginning of the 2025-26 financial year.

As discussed in Section 2, the data is not intended to include FOAK costs. Therefore, for technologies not recently constructed in Australia, the cost of the first plant may be higher than estimated here. Section 2 includes suggested FOAK premiums.

Furthermore, capital costs are for a location not greater than 200km from the Victorian metropolitan area. GHD provide data for adjusting costs for different locations in the NEM. Site conditions will also impact costs to varying degrees, depending on the technology.

All capital costs are for the alternating current power rating of the equipment with the exception of rooftop solar which is on a direct current basis. Power is also on a net basis after auxiliary loads. Capital costs are before any subsidies that may be available.

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 (16hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear SMR	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2940	1764	6962	2022	2648	9016	25712	1621	1216	7562	3248	5433	8325	15842	30290	12420	7000	10332
2026	6756	12685	10400	2427	2824	1694	6707	2014	2619	8631	25277	1536	1192	7416	3123	5358	7222	15330	28775	11951	6940	10153
2027	6585	12465	10108	2360	2716	1629	6463	2010	2594	8387	24850	1456	1171	7306	3004	5306	6504	14835	26703	11500	6881	10000
2028	6436	12284	9852	2298	2566	1540	6234	2009	2573	8287	24430	1380	1156	7244	2896	5279	6171	14356	25179	11066	6822	9877
2029	6297	12118	9613	2238	2427	1456	6016	2009	2554	8316	24017	1307	1145	7209	2793	5271	6164	13893	23998	10649	6763	9764
2030	6164	11961	9385	2180	2296	1377	5807	2010	2537	8349	23611	1239	1135	7197	2697	5268	6163	13444	23925	10247	6705	9658
2031	6033	11805	9161	2124	2173	1304	5606	2011	2519	8381	23211	1174	1127	7196	2607	5269	6166	13010	23850	9860	6648	9552
2032	5902	11644	8938	2069	2056	1233	5410	2011	2501	8411	22819	1113	1121	7191	2525	5275	6172	12590	23952	9488	6591	9442
2033	5772	11481	8717	2015	1946	1167	5220	2010	2482	8439	22433	1055	1117	7121	2453	5280	6166	12183	24048	9130	6534	9330
2034	5644	11320	8501	1962	1842	1105	5037	2010	2463	8467	22054	1000	1115	6999	2395	5285	6136	11790	24145	8786	6478	9220
2035	5567	11220	8371	1929	1776	1066	4913	2012	2454	8495	21681	947	1113	6833	2384	5289	6088	11409	24241	8454	6423	9159
2036	5541	11176	8325	1916	1747	1048	4842	2017	2453	8524	21749	942	1110	6699	2353	5292	6038	11489	24339	8493	6450	9149
2037	5563	11196	8362	1922	1752	1051	4830	2024	2462	8553	21815	938	1108	6593	2350	5294	5998	11502	24438	8499	6470	9189
2038	5587	11227	8400	1928	1757	1054	4828	2031	2471	8582	21893	931	1106	6522	2347	5297	5964	11515	24170	8504	6484	9229
2039	5610	11268	8437	1934	1762	1057	4835	2038	2480	8612	21980	925	1104	6477	2345	5299	5934	11528	22245	8510	6492	9269
2040	5631	11299	8472	1939	1767	1060	4834	2045	2488	8638	22053	918	1103	6456	2343	5301	5918	11539	19646	8516	6502	9306
2041	5649	11311	8503	1944	1770	1062	4819	2050	2494	8661	22105	912	1102	6438	2340	5304	5913	11550	17398	8522	6514	9339
2042	5666	11310	8531	1948	1773	1064	4794	2055	2500	8680	22139	908	1100	6428	2337	5308	5917	11560	16791	8528	6529	9368
2043	5683	11307	8558	1952	1776	1066	4768	2060	2506	8700	22173	904	1099	6406	2332	5312	5921	11569	16838	8534	6542	9398
2044	5699	11296	8586	1955	1780	1068	4734	2065	2512	8719	22198	900	1098	6402	2328	5317	5926	11579	16886	8540	6558	9428
2045	5715	11277	8615	1959	1783	1070	4693	2070	2518	8739	22217	896	1097	6381	2324	5321	5931	11589	16934	8545	6574	9457
2046	5732	11254	8643	1963	1786	1071	4648	2075	2524	8758	22233	892	1096	6366	2320	5326	5936	11598	16983	8551	6588	9487
2047	5750	11241	8671	1967	1789	1073	4613	2080	2530	8778	22257	889	1096	6308	2317	5330	5940	11608	17032	8557	6594	9517
2048	5768	11237	8700	1971	1792	1075	4585	2085	2537	8798	22290	875	1095	6232	2313	5334	5945	11618	17081	8563	6592	9548
2049	5786	11240	8729	1974	1795	1077	4563	2090	2543	8818	22330	863	1093	6139	2300	5339	5950	11628	17130	8569	6583	9578
2050	5803	11254	8756	1978	1798	1079	4553	2095	2548	8836	22378	851	1091	6089	2290	5344	5955	11637	17176	8576	6579	9607
2051	5820	11270	8782	1981	1801	1081	4545	2099	2554	8853	22426	838	1083	6050	2268	5348	5959	11646	17219	8582	6567	9634
2052	5835	11293	8806	1984	1803	1082	4544	2103	2558	8869	22478	827	1077	6038	2256	5353	5964	11654	17259	8588	6566	9660
2053	5848	11308	8830	1987	1806	1083	4536	2107	2563	8884	22522	800	1068	6006	2237	5357	5968	11662	17299	8594	6536	9685
2054	5861	11330	8855	1990	1808	1085	4534	2111	2568	8899	22574	786	1066	5997	2230	5361	5972	11671	17340	8600	6523	9711
2055	5866	11337	8867	1991	1809	1085	4530	2113	2571	8907	22596	771	1064	5983	2223	5363	5974	11675	17360	8603	6502	9724

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 (16hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear SMR	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2914	1764	6962	2022	2648	9016	25712	1621	1216	7562	3248	5433	8325	15842	30290	12420	7000	10332
2026	6769	12703	10419	2429	2773	1679	6707	2017	2622	8828	25450	1382	1184	7259	3100	4882	6880	15376	28112	11991	6805	10171
2027	6617	12514	10156	2366	2641	1599	6467	2016	2602	8660	25190	1171	1157	6969	2961	4375	5614	14923	26040	11577	6616	10046
2028	6498	12387	9946	2309	2524	1528	6248	2022	2590	8516	24933	996	1136	6907	2835	3928	4590	14484	24157	11177	6433	9967
2029	6396	12291	9765	2256	2418	1464	6043	2030	2581	8388	24679	848	1117	6877	2718	3532	3757	14057	22444	10791	6254	9912
2030	6296	12196	9588	2204	2319	1404	5846	2039	2574	8292	24427	743	1101	6869	2608	3281	3257	13643	20271	10418	6080	9858
2031	6188	12083	9399	2152	2199	1331	5651	2046	2563	8224	24178	677	1085	6872	2505	3159	3028	13242	18697	10058	5911	9790
2032	6074	11952	9200	2099	2084	1262	5458	2050	2550	8191	23932	652	1073	6873	2410	3153	3021	12852	17682	9711	5747	9708
2033	5957	11815	8999	2048	1975	1196	5270	2054	2536	8159	23688	642	1066	6856	2326	3146	3014	12474	17809	9375	5587	9620
2034	5843	11680	8803	1997	1872	1133	5089	2058	2522	8131	23446	641	1064	6670	2258	3139	3008	12106	17936	9052	5432	9533
2035	5782	11517	8695	1967	1808	1095	4887	2064	2517	8088	23207	623	1061	6495	2238	3134	3002	11750	17383	8739	5281	9499
2036	5772	11416	8674	1957	1781	1078	4742	2073	2522	8072	23264	606	1060	6288	2194	3132	3000	11643	16826	8605	5317	9516
2037	5814	11380	8739	1966	1788	1083	4655	2085	2536	8079	23317	589	1059	6230	2176	3132	2999	11669	16266	8621	5353	9585
2038	5857	11438	8806	1975	1796	1088	4653	2097	2551	8123	23461	588	1060	6185	2161	3133	3000	11695	16386	8636	5391	9656
2039	5900	11494	8873	1985	1804	1092	4648	2109	2566	8167	23605	586	1062	6149	2155	3136	3002	11722	16507	8652	5429	9727
2040	5941	11551	8937	1994	1811	1097	4645	2120	2579	8205	23745	584	1058	6122	2153	3139	3004	11747	16622	8668	5465	9795
2041	5981	11609	8998	2002	1818	1101	4646	2131	2592	8239	23881	582	1047	6101	2153	3144	3008	11772	16732	8684	5499	9859
2042	6018	11675	9055	2009	1824	1104	4655	2141	2604	8271	24021	580	1030	6085	2153	3149	3012	11795	16835	8700	5530	9920
2043	6055	11744	9114	2016	1830	1108	4666	2151	2616	8301	24164	578	1009	6074	2153	3155	3017	11819	16940	8271	5554	9982
2044	6093	11815	9173	2023	1836	1112	4679	2160	2628	8332	24310	576	994	6067	2152	3161	3021	11843	17045	7842	5578	10044
2045	6131	11890	9232	2031	1842	1115	4695	2171	2640	8360	24460	575	980	6064	2151	3167	3026	11867	17152	7403	5604	10107
2046	6169	11966	9292	2038	1848	1119	4712	2181	2653	8395	24613	573	974	6064	2149	3174	3031	11891	17259	7408	5636	10171
2047	6208	12045	9353	2046	1855	1123	4729	2191	2665	8429	24768	572	969	6066	2147	3180	3036	11916	17368	7413	5669	10235
2048	6247	12124	9414	2054	1861	1127	4747	2201	2678	8466	24925	570	970	6072	2145	3186	3041	11729	17478	7428	5698	10299
2049	6287	12203	9476	2061	1867	1131	4765	2212	2691	8501	25083	567	945	6079	2142	3191	3046	11454	17589	7289	5653	10365
2050	6326	12282	9537	2069	1874	1134	4782	2222	2703	8534	25238	564	920	6076	2141	3197	3051	11178	17698	7150	5607	10429
2051	6364	12358	9597	2076	1879	1138	4798	2232	2715	8566	25390	559	891	6107	2136	3204	3056	11066	17804	7011	5560	10491
2052	6401	12433	9655	2083	1885	1141	4814	2241	2726	8600	25538	558	890	6072	2136	3211	3062	11042	17908	7025	5587	10553
2053	6439	12506	9714	2090	1891	1145	4827	2251	2738	8630	25685	555	880	6103	2130	3218	3068	10990	18013	7039	5612	10615
2054	6476	12580	9773	2096	1896	1148	4841	2260	2750	8661	25834	555	875	6070	2131	3226	3074	10983	18119	7053	5640	10677
2055	6495	12615	9803	2100	1899	1150	4847	2265	2756	8674	25907	553	868	6102	2128	3229	3077	10965	18172	7060	5653	10708

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 (16hrs)	Wind	Offshore wind fixed	Offshore wind floating	Wave	Nuclear (SMR)	Tidal /ocean current	Fuel cell	Nuclear large-scale
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	6946	12941	10725	2497	2914	1764	6962	2022	2648	9016	25712	1621	1216	7562	3248	5433	8325	15842	30290	12420	7000	10332
2026	6761	12687	10406	2428	2771	1678	6703	2015	2620	8854	25321	1381	1191	7474	3108	5404	7796	15367	28775	11983	6804	10159
2027	6596	12472	10121	2362	2637	1597	6456	2012	2596	8705	24937	1187	1171	7417	2976	5383	7297	14906	26703	11561	6613	10013
2028	6456	12303	9879	2301	2516	1523	6227	2012	2578	8574	24558	1066	1155	7395	2855	5369	6839	14460	24554	11155	6428	9902
2029	6329	12156	9658	2243	2405	1456	6010	2015	2562	8453	24184	989	1141	7384	2742	5360	6415	14026	22351	10762	6248	9808
2030	6207	12015	9446	2188	2303	1394	5802	2019	2548	8382	23817	930	1126	7372	2636	5306	6103	13606	20114	10384	6073	9718
2031	6084	11869	9233	2133	2181	1320	5600	2021	2532	8327	23455	872	1114	7346	2536	5186	5878	13198	18498	10018	5903	9624
2032	5957	11713	9016	2078	2064	1250	5402	2022	2515	8320	23098	831	1104	7321	2445	5020	5706	12802	17453	9666	5738	9522
2033	5832	11556	8802	2025	1954	1183	5211	2023	2498	8319	22747	806	1095	7204	2365	4886	5558	12418	17544	9326	5577	9418
2034	5710	11402	8593	1973	1851	1121	5027	2024	2481	8352	22401	788	1087	7046	2301	4804	5454	12046	17636	8998	5421	9315
2035	5639	11321	8471	1941	1786	1081	4912	2028	2473	8385	22061	772	1080	6852	2285	4758	5418	11685	17171	8681	5269	9264
2036	5619	11312	8434	1929	1758	1064	4865	2034	2475	8420	22177	759	1075	6735	2252	4718	5388	11532	16704	8524	5244	9264
2037	5650	11375	8481	1936	1764	1068	4882	2043	2485	8454	22297	749	1070	6658	2244	4684	5362	11548	16236	8533	5230	9314
2038	5680	11439	8529	1943	1770	1071	4901	2052	2496	8489	22418	742	1065	6620	2235	4654	5340	11564	16324	8541	5228	9365
2039	5711	11434	8577	1950	1776	1075	4857	2061	2507	8525	22477	734	1061	6608	2217	4624	5241	11581	16414	8549	5223	9416
2040	5740	11425	8622	1957	1781	1078	4812	2069	2517	8557	22528	725	1059	6618	2201	4597	5144	11596	16497	8558	5225	9464
2041	5767	11407	8663	1963	1786	1081	4760	2077	2526	8586	22565	717	1056	6632	2182	4573	5049	11610	16574	8566	5230	9508
2042	5792	11452	8702	1968	1790	1084	4768	2083	2534	8611	22656	709	1055	6595	2169	4556	5037	11623	16644	8574	5247	9548
2043	5816	11498	8740	1973	1794	1086	4776	2090	2542	8637	22748	704	1054	6490	2160	4541	5027	11636	16715	8583	5260	9589
2044	5841	11498	8779	1978	1798	1089	4743	2096	2550	8662	22798	698	1054	6357	2154	4528	5018	11650	16787	8591	5267	9630
2045	5866	11495	8818	1983	1802	1091	4707	2103	2558	8688	22845	691	1053	6234	2148	4517	5010	11663	16858	8600	5252	9671
2046	5892	11491	8857	1988	1807	1094	4670	2110	2567	8714	22893	685	1054	6163	2144	4507	5004	11676	16931	8609	5222	9713
2047	5917	11539	8897	1993	1811	1096	4679	2117	2575	8741	22988	679	1054	6088	2141	4498	4998	11690	17004	8617	5184	9754
2048	5942	11590	8937	1998	1815	1099	4691	2124	2583	8767	23087	675	1055	6032	2139	4491	4994	11703	17077	8626	5162	9797
2049	5968	11642	8977	2003	1819	1102	4703	2130	2592	8794	23187	668	1054	5975	2138	4479	4986	11717	17151	8635	5158	9839
2050	5993	11692	9015	2008	1823	1104	4714	2137	2600	8819	23283	664	1054	5949	2137	4472	4982	11730	17223	8644	5171	9880
2051	6017	11735	9053	2013	1827	1106	4720	2143	2607	8843	23370	660	1054	5936	2136	4458	4972	11742	17291	8652	5184	9919
2052	6040	11775	9088	2017	1831	1108	4724	2149	2614	8865	23454	659	1055	5942	2137	4454	4970	11754	17357	8661	5198	9957
2053	6063	11806	9125	2021	1834	1110	4720	2155	2621	8887	23528	656	1055	5926	2136	4438	4958	11767	17423	8670	5194	9995
2054	6086	11842	9161	2025	1838	1113	4721	2161	2629	8910	23608	655	1056	5920	2137	4434	4956	11779	17489	8679	5193	10033
2055	6097	11855	9179	2027	1839	1114	4717	2164	2632	8921	23644	654	1057	5906	2137	4426	4951	11785	17523	8684	5183	10052

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
2025	778	778	778	310	310	311	467	467	467	525	525	525	290	290	290	235	235	235
2026	760	717	673	306	289	272	455	428	401	514	485	456	285	270	254	229	215	202
2027	747	668	590	302	273	244	445	395	346	505	453	401	282	255	227	224	199	174
2028	740	630	521	299	260	221	441	370	300	500	429	357	279	243	206	221	186	151
2029	734	599	464	297	251	205	438	349	260	497	409	322	277	234	191	220	175	130
2030	717	589	420	289	243	195	428	345	225	484	400	295	269	227	182	215	173	113
2031	698	578	407	281	236	186	418	341	222	471	392	284	262	220	173	210	171	111
2032	689	567	394	273	229	177	417	337	218	463	383	274	254	214	165	209	169	109
2033	676	556	380	265	222	168	411	334	212	453	375	263	247	207	157	206	167	106
2034	647	546	369	257	216	160	390	330	209	435	366	254	240	201	149	196	165	105
2035	627	535	359	250	210	152	378	326	207	422	359	246	233	195	142	189	163	104
2036	611	526	350	243	203	145	369	322	205	411	351	238	226	189	135	185	161	103
2037	597	516	343	236	197	138	361	319	205	400	343	231	219	184	128	181	160	103
2038	585	506	336	229	192	131	356	315	204	391	336	224	213	178	122	178	158	102
2039	573	497	329	222	186	125	351	311	204	382	329	218	206	173	116	176	156	102
2040	568	492	329	219	185	125	348	308	204	378	326	218	204	172	116	174	154	102
2041	562	487	328	217	183	124	345	304	204	374	322	218	202	170	116	173	152	102
2042	558	482	328	215	182	124	343	300	204	372	320	218	200	169	115	172	150	102
2043	555	478	329	213	181	124	341	297	205	369	317	218	198	169	115	171	148	102
2044	552	474	329	212	181	124	340	293	205	367	314	218	197	168	115	170	147	103
2045	550	469	329	211	180	124	339	289	205	366	312	218	196	167	115	170	145	103
2046	548	465	330	210	180	124	338	286	206	364	310	218	195	167	115	169	143	103
2047	547	462	330	209	179	124	337	282	206	363	308	218	195	166	115	169	141	103
2048	545	458	331	209	179	124	336	279	207	362	306	219	194	166	115	168	139	104
2049	541	454	332	208	179	124	332	275	208	360	304	219	194	166	115	166	138	104
2050	537	451	332	208	179	124	329	272	208	358	302	219	193	166	116	164	136	104
2051	538	447	333	208	179	125	329	269	209	358	300	220	193	166	116	165	134	104
2052	534	444	334	207	178	125	326	265	209	356	298	221	193	166	116	163	133	105
2053	535	440	335	208	179	125	327	262	210	356	297	221	193	166	116	163	131	105
2054	532	437	336	207	178	125	325	259	211	355	295	222	192	166	116	162	129	106
2055	533	446	337	207	178	125	325	268	212	355	300	222	192	166	116	163	134	106

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
2025	385	385	385	265	265	265	120	120	120	308	308	308	245	245	245	63	63	63
2026	377	356	335	260	246	232	117	110	103	301	285	268	240	227	214	61	58	54
2027	371	333	296	257	232	207	114	101	89	297	268	238	237	214	191	60	53	47
2028	367	316	265	254	221	188	113	95	77	294	254	214	235	204	174	59	50	40
2029	364	302	241	252	213	174	112	89	66	292	243	196	233	197	161	59	47	35
2030	355	295	223	246	207	166	109	88	58	284	237	183	227	191	153	57	46	30
2031	345	288	214	238	201	158	107	87	57	276	231	175	220	185	146	56	46	30
2032	338	281	206	231	195	150	106	86	56	269	225	168	213	180	138	56	45	29
2033	330	274	197	225	189	143	105	85	54	262	219	160	207	174	132	55	45	28
2034	318	267	189	218	183	136	100	84	53	253	213	153	201	169	125	52	44	28
2035	308	261	182	212	178	129	96	83	53	246	207	147	195	164	119	50	44	28
2036	299	254	175	206	172	123	94	82	52	239	202	141	189	159	113	49	43	27
2037	291	248	169	199	167	117	92	81	52	232	196	135	184	154	108	48	42	27
2038	284	242	163	194	162	111	91	80	52	226	191	130	178	149	102	47	42	27
2039	277	236	158	188	157	106	89	79	52	220	186	124	173	145	97	47	41	27
2040	274	234	157	185	156	105	88	78	52	217	184	124	171	144	97	46	41	27
2041	271	232	157	183	155	105	88	77	52	215	183	124	169	142	97	46	40	27
2042	269	230	157	182	154	105	87	76	52	213	182	124	167	142	97	46	40	27
2043	267	228	157	180	153	105	87	75	52	211	180	124	166	141	96	45	39	27
2044	265	227	157	179	152	105	86	74	52	210	179	124	165	140	96	45	39	27
2045	264	225	157	178	152	105	86	73	52	209	178	124	164	140	96	45	38	27
2046	263	224	157	177	151	105	86	73	52	208	177	124	163	139	96	45	38	27
2047	262	223	157	177	151	105	86	72	52	207	177	124	163	139	96	45	37	27
2048	262	222	157	176	151	105	85	71	53	207	176	124	162	139	96	45	37	27
2049	260	221	157	176	151	105	84	70	53	206	175	124	162	139	96	44	37	28
2050	259	220	158	175	151	105	83	69	53	205	175	124	161	139	97	44	36	28
2051	259	219	158	176	151	105	83	68	53	205	174	124	162	139	97	44	36	28
2052	258	218	158	175	150	105	83	67	53	204	174	125	161	138	97	43	35	28
2053	258	217	159	175	151	105	83	66	53	204	173	125	161	139	97	43	35	28
2054	257	216	159	175	150	105	82	66	54	204	173	125	161	138	97	43	34	28
2055	257	218	159	175	150	106	83	68	54	204	174	125	161	138	97	43	35	28

Apx Table B.6 Twelve- and twenty-four hour battery cost data by storage duration, component and total costs (multiply by duration to convert to $/kW)

	Battery storage (12 hrs)									Battery storage (24 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
2025	287	287	287	245	245	245	42	42	42	266	266	266	245	245	245	21	21	21
2026	281	266	250	240	227	214	41	38	36	261	246	232	240	227	214	20	19	18
2027	277	250	222	237	214	191	40	35	31	257	232	207	237	214	191	20	18	16
2028	274	237	201	235	204	174	39	33	27	255	221	187	235	204	174	20	17	13
2029	272	228	184	233	197	161	39	31	23	252	212	172	233	197	161	20	16	12
2030	265	222	173	227	191	153	38	31	20	246	206	163	227	191	153	19	15	10
2031	257	216	165	220	185	146	37	31	20	239	200	155	220	185	146	19	15	10
2032	251	210	158	213	180	138	37	30	19	232	195	148	213	180	138	19	15	10
2033	244	204	151	207	174	132	37	30	19	226	189	141	207	174	132	18	15	9
2034	236	198	144	201	169	125	35	29	19	218	183	134	201	169	125	17	15	9
2035	229	193	137	195	164	119	34	29	18	212	178	128	195	164	119	17	15	9
2036	222	187	131	189	159	113	33	29	18	206	173	122	189	159	113	16	14	9
2037	216	182	126	184	154	108	32	28	18	200	168	117	184	154	108	16	14	9
2038	210	177	120	178	149	102	32	28	18	194	163	111	178	149	102	16	14	9
2039	204	172	115	173	145	97	31	28	18	188	159	106	173	145	97	16	14	9
2040	201	171	115	171	144	97	31	27	18	186	157	106	171	144	97	15	14	9
2041	199	169	115	169	142	97	31	27	18	184	156	106	169	142	97	15	13	9
2042	198	168	115	167	142	97	30	27	18	182	155	106	167	142	97	15	13	9
2043	196	167	115	166	141	96	30	26	18	181	154	106	166	141	96	15	13	9
2044	195	166	115	165	140	96	30	26	18	180	153	105	165	140	96	15	13	9
2045	194	165	115	164	140	96	30	26	18	179	153	105	164	140	96	15	13	9
2046	193	165	115	163	139	96	30	25	18	178	152	105	163	139	96	15	13	9
2047	192	164	115	163	139	96	30	25	18	178	152	105	163	139	96	15	12	9
2048	192	164	115	162	139	96	30	25	18	177	151	106	162	139	96	15	12	9
2049	191	163	115	162	139	96	29	24	18	176	151	106	162	139	96	15	12	9
2050	190	163	115	161	139	97	29	24	18	176	151	106	161	139	97	15	12	9
2051	191	162	115	162	139	97	29	24	18	176	151	106	162	139	97	15	12	9
2052	190	162	115	161	138	97	29	23	19	175	150	106	161	138	97	14	12	9
2053	190	162	116	161	139	97	29	23	19	176	150	106	161	139	97	14	12	9
2054	189	161	116	161	138	97	29	23	19	175	150	106	161	138	97	14	11	9
2055	189	162	116	161	138	97	29	24	19	175	150	107	161	138	97	14	12	9

Apx Table B.7 Pumped hydro storage cost data by duration, by scenario, total cost basis

	$/kW												$/kWh											
	Current policies				Global NZE post 2050				Global NZE by 2050				Current policies				Global NZE post 2050				Global NZE by 2050			
	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs	10hrs	24hrs	48hrs	160hrs
2025	3535	4364	5192	8879	3535	4364	5192	8879	3535	4364	5192	8879	354	182	108	55	354	182	108	55	354	182	108	55
2026	3468	4280	5093	8709	3468	4280	5093	8709	3468	4280	5093	8709	347	178	106	54	347	178	106	54	347	178	106	54
2027	3402	4199	4996	8544	3402	4199	4996	8544	3402	4199	4996	8544	340	175	104	53	340	175	104	53	340	175	104	53
2028	3336	4118	4899	8378	3336	4118	4899	8378	3336	4118	4899	8378	334	172	102	52	334	172	102	52	334	172	102	52
2029	3267	4032	4798	8205	3267	4032	4798	8205	3267	4032	4798	8205	327	168	100	51	327	168	100	51	327	168	100	51
2030	3198	3947	4696	8031	3198	3947	4696	8031	3198	3947	4696	7131	320	164	98	50	320	164	98	50	320	164	98	45
2031	3215	3968	4721	8074	3218	3972	4726	8081	3228	3985	4726	7199	321	165	98	50	322	165	98	51	323	166	98	45
2032	3228	3984	4741	8107	3233	3991	4749	8121	3252	4014	4749	7251	323	166	99	51	323	166	99	51	325	167	99	45
2033	3242	4001	4761	8142	3250	4011	4772	8161	3275	4043	4772	7304	324	167	99	51	325	167	99	51	328	168	99	46
2034	3255	4018	4781	8175	3266	4032	4797	8203	3301	4075	4797	7361	326	167	100	51	327	168	100	51	330	170	100	46
2035	3269	4035	4800	8209	3283	4052	4822	8245	3327	4107	4822	7420	327	168	100	51	328	169	100	52	333	171	100	46
2036	3282	4051	4820	8243	3300	4073	4846	8288	3354	4140	4846	7479	328	169	100	52	330	170	101	52	335	172	101	47
2037	3296	4068	4841	8278	3317	4095	4872	8331	3381	4173	4872	7539	330	170	101	52	332	171	101	52	338	174	101	47
2038	3310	4086	4861	8313	3335	4116	4897	8375	3408	4206	4897	7599	331	170	101	52	333	171	102	52	341	175	102	47
2039	3324	4103	4882	8349	3352	4138	4923	8419	3436	4240	4923	7661	332	171	102	52	335	172	103	53	344	177	103	48
2040	3339	4121	4903	8384	3370	4160	4949	8464	3464	4275	4949	7723	334	172	102	52	337	173	103	53	346	178	103	48
2041	3349	4133	4918	8410	3384	4176	4969	8498	3487	4304	4969	7776	335	172	102	53	338	174	104	53	349	179	104	49
2042	3359	4145	4932	8435	3397	4193	4989	8532	3511	4334	4989	7830	336	173	103	53	340	175	104	53	351	181	104	49
2043	3369	4158	4947	8460	3411	4210	5009	8566	3535	4364	5009	7884	337	173	103	53	341	175	104	54	354	182	104	49
2044	3379	4171	4962	8486	3425	4227	5029	8601	3560	4394	5029	7938	338	174	103	53	342	176	105	54	356	183	105	50
2045	3389	4183	4977	8512	3439	4244	5050	8636	3585	4424	5050	7993	339	174	104	53	344	177	105	54	358	184	105	50
2046	3399	4196	4992	8537	3453	4261	5070	8671	3609	4455	5070	8048	340	175	104	53	345	178	106	54	361	186	106	50
2047	3410	4209	5007	8563	3467	4279	5091	8706	3635	4486	5091	8105	341	175	104	54	347	178	106	54	363	187	106	51
2048	3420	4221	5023	8589	3481	4296	5112	8742	3660	4517	5112	8161	342	176	105	54	348	179	106	55	366	188	106	51
2049	3431	4234	5038	8616	3495	4314	5133	8777	3686	4549	5133	8218	343	176	105	54	349	180	107	55	369	190	107	51
2050	3441	4247	5053	8642	3509	4331	5154	8813	3711	4581	5154	8276	344	177	105	54	351	180	107	55	371	191	107	52
2051	3450	4258	5066	8663	3522	4347	5172	8844	3735	4611	5172	8329	345	177	106	54	352	181	108	55	374	192	108	52
2052	3458	4268	5079	8685	3534	4362	5190	8875	3760	4640	5190	8383	346	178	106	54	353	182	108	55	376	193	108	52
2053	3467	4279	5091	8707	3547	4377	5208	8907	3784	4670	5208	8438	347	178	106	54	355	182	109	56	378	195	109	53
2054	3476	4290	5104	8729	3559	4393	5227	8938	3809	4701	5227	8492	348	179	106	55	356	183	109	56	381	196	109	53
2055	3484	4301	5117	8750	3572	4409	5245	8970	3833	4731	5245	8548	348	179	107	55	357	184	109	56	383	197	109	53

Apx Table B.8 Historical storage cost data, total cost basis

	$/kW											$/kWh										
	Battery (1hr)	Battery (2hrs)	Battery (4hrs)	Battery (8hrs)	PHES (6hrs)	PHES (8hrs)	PHES (10hrs)	PHES (12hrs)	PHES (24hrs)	PHES (48hrs)	PHES 160hrs)	Battery (1hr)	Battery (2hrs)	Battery (4hrs)	Battery (8hrs)	PHES (6hrs)	PHES (8hrs)	PHES (10hrs)	PHES (12hrs)	PHES (24hrs)	PHES (48hrs)	PHES 160hrs)
2019		1535	2424	4404	2283	2461		2614	3875	4341			768	606	551	308	249		177	131	88	
2020	977	1310	2086	3676	2877	3004		3292	4232	6358		977	655	521	460	387	303		222	142	128	
2021	942	1257	1942	3407	2771	3006		3234	4219	6337		942	629	485	426	387	315		226	147	133	
2022	1046	1513	2454	4360	3245	3526		3786	4949	7434		1046	756	614	545	481	392		281	184	165	
2023	1069	1549	2510	4400	4037	4387		4617	6156	7226		1069	775	627	550	635	517		363	242	170	
2024	929	1241	1727	2809			7837		6632	7985		929	621	432	351			768		271	196	
2025	778	1050	1540	2464			3535		4364	5192	8879	778	525	385	308			354		182	130	55

Notes: Batteries are large scale. Small scale batteries of 10kWh for home use with 2-hour duration are estimated at $1100/kWh before subsidies (GHD, 2025). However, lower costs may be available for larger household battery sizes.

Apx Table B.9 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
2025	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	6962	13.3	89%	6962	19.5	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	2497	13.3	89%	2497	19.5	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2886	13.3	20%	2886	19.5	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	2886	13.3	20%	2886	19.5	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2022	13.3	20%	2022	19.5	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2648	40.7	20%	2648	41.9	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	12941	3.0	89%	12941	4.5	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	6946	3.0	89%	6946	4.5	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	10725	0.6	89%	10725	0.7	53%
Nuclear SMR	30	4.4	33%	200	5.3	0.0	30290	1.1	89%	30290	1.3	53%
Nuclear large-scale	30	5.8	33%	200	5.3	0.0	10332	1.1	89%	10332	1.3	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	8278	0.0	71%	8179	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	1621	0.0	32%	1621	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	3248	0.0	48%	3248	0.0	29%
Wind offshore (fixed)	25	3.0	100%	175.0	0.0	0.0	5433	0.0	52%	5433	0.0	40%
2030												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	5807	9.4	89%	5846	16.5	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	2180	9.4	89%	2204	16.5	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	2296	9.4	20%	2319	16.5	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1377	9.4	20%	1404	16.5	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2010	9.4	20%	2039	16.5	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2574	37.7	20%	2537	40.9	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11961	3.1	89%	12196	5.5	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	6164	3.1	89%	6296	5.5	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	9385	0.7	89%	9588	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	20271	0.8	89%	23925	1.0	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9658	0.8	89%	9858	1.0	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	9020	0.0	71%	9338	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	743	0.0	32%	1239	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2608	0.0	48%	2697	0.0	29%
Wind offshore (fixed)	25	3.0	100%	175.0	0.0	0.0	3281	0.0	54%	5268	0.0	40%

2040												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	4645	9.2	89%	4834	16.1	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	1939	9.2	89%	1994	16.1	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1767	9.2	20%	1811	16.1	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1060	9.2	20%	1097	16.1	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2045	9.2	20%	2120	16.1	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2579	31.0	20%	2488	36.6	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11299	2.9	89%	11551	4.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5631	2.9	89%	5941	4.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8472	0.7	89%	8937	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	16622	0.5	89%	19646	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9306	0.5	89%	9795	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	8040	0.0	71%	8377	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	584	0.0	32%	918	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2153	0.0	48%	2343	0.0	29%
Wind offshore (fixed)	25	3.0	100%	175.0	0.0	0.0	3139	0.0	57%	5301	0.0	40%
2050												
Gas with CCS	25	2.0	44%	46.0	8.0	8.6	4782	9.2	89%	4553	16.1	53%
Gas combined cycle	25	2.0	51%	36.0	5.0	0.0	1978	9.2	89%	2069	16.1	53%
Gas open cycle (small)	25	1.5	36%	17.4	16.1	0.0	1798	9.2	20%	1874	16.1	20%
Gas open cycle (large)	25	1.5	33%	26.0	10.0	0.0	1079	9.2	20%	1134	16.1	20%
Gas reciprocating	25	1.1	41%	29.4	8.5	0.0	2095	9.2	20%	2222	16.1	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2703	28.5	20%	2548	35.8	20%
Black coal with CCS	30	2.0	30%	94.8	8.9	14.1	11254	2.9	89%	12282	4.6	53%
Black coal	30	2.0	42%	64.9	4.7	0.0	5803	2.9	89%	6326	4.6	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8756	0.7	89%	9537	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	17176	0.5	89%	17698	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	9607	0.5	89%	10429	0.7	53%
Solar thermal	30	1.8	100%	124.2	0.0	0.0	7978	0.0	71%	7900	0.0	57%
Large scale solar PV	30	0.5	100%	12.0	0.0	0.0	564	0.0	32%	851	0.0	19%
Wind onshore	25	1.0	100%	29.0	0.0	0.0	2141	0.0	48%	2290	0.0	29%
Wind offshore (fixed)	25	3.0	100%	175.0	0.0	0.0	3197	0.0	61%	5344	0.0	40%

Notes: Economic life is the design life or the period of financing. Total operational life, with refurbishment expenses, is not included in the LCOE calculation but is used in electricity system modelling to understand natural retirement dates. Large-scale solar PV is single axis tracking. The real discount rate for all technologies is 7%.

Apx Table B.10 Electricity generation technology LCOE projections data, 2025-26 $/MWh

Category	Technology	2025		2030		2040		2050	
		Low	High	Low	High	Low	High	Low	High
Peaking 20% load	Gas open cycle (small)	316	377	245	317	214	285	216	289
	Gas open cycle (large)	325	392	201	280	182	258	183	260
	Gas reciprocating	249	303	214	278	214	279	217	284
	H_2 reciprocating	616	629	578	611	503	561	481	555
Flexible load, high emission	Black coal	121	195	113	191	105	176	107	183
	Brown coal	167	272	149	246	137	232	141	245
	Gas	135	203	104	176	99	169	100	170
Flexible load, low emission	Black coal with CCS	224	354	214	351	204	328	204	342
	Gas with CCS	219	333	173	286	157	261	158	255
	Nuclear SMR	465	772	322	619	268	516	276	470
	Nuclear large-scale	200	328	187	312	178	307	183	323
	Solar thermal	140	175	151	196	136	178	136	170
Variable	Solar photovoltaic	52	88	26	69	22	53	21	50
	Wind onshore	78	129	64	109	54	96	54	94
	Wind offshore (fixed)	164	213	110	208	101	209	96	210

Apx Table B.11 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
2025	2100	2730	2100	2730	2100	2730
2026	2058	2675	1818	2363	1873	2435
2027	2017	2622	1589	2066	1692	2199
2028	1977	2569	1395	1813	1530	1989
2029	1937	2518	1228	1597	1387	1803
2030	1898	2468	1081	1406	1258	1635
2031	1860	2418	1067	1388	1242	1614
2032	1861	2420	1068	1388	1234	1604
2033	1796	2334	1030	1339	1231	1600
2034	1742	2264	999	1299	1218	1583
2035	1713	2227	983	1278	1222	1589
2036	1688	2194	968	1259	1226	1594
2037	1630	2119	935	1216	1231	1600
2038	1587	2063	910	1184	1194	1553
2039	1553	2020	891	1159	1190	1547
2040	1527	1985	876	1139	1150	1495
2041	1506	1957	864	1123	1135	1476
2042	1488	1934	854	1110	1125	1463
2043	1474	1916	845	1099	1098	1427
2044	1462	1900	839	1090	1092	1419
2045	1434	1865	823	1070	1078	1401
2046	1385	1800	795	1033	1077	1400
2047	1349	1753	774	1006	1072	1393
2048	1321	1718	758	986	1072	1394
2049	1300	1690	746	970	1070	1392
2050	1284	1669	737	958	1059	1377
2051	1292	1680	741	964	1063	1382
2052	1279	1663	734	954	1060	1378
2053	1287	1673	738	960	1064	1383
2054	1265	1644	726	944	1065	1384
2055	1273	1655	730	949	1069	1389

Apx Table B.12 System levelised cost of electricity by cost component, $/MWh

	2030	2050	
	82% renewable target	Moderate net zero	Strong net zero
VRE capital	43.7	56.7	60.2
Peaking capital	0.0	8.9	8.7
Storage	7.5	15.2	17.0
O&M	6.4	10.2	10.3
IBR cost	2.4	2.2	2.3
Connection	4.5	7.4	7.8
Fuel	16.6	14.1	17.8
REZ transmission	5.7	8.6	9.4
Other transmission	4.0	11.6	14.6
Total - generation	81.2	114.7	124.0
Total - generation and transmission	90.9	135.0	148.1

VRE-– variable renewable generation; IBR - Inverter-based resources cost such as deployment of synchronous condensers and grid-forming batteries; REZ – renewable energy zone. O&M – operating and maintenance costs

Appendix C Data assumptions

C.1 Technologies and learning rates

The technical approach to applying learning rates is explained in Appendix A and involves a specific mathematical formula. The projection approach uses two global and local learning models (GALLM) which contain applications of the learning formula. One model 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 four hydrogen production technologies. Where appropriate, these have been split into their components of which there are 21 (noting that in total 52 items are modelled). 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 and hydrogen technologies.

Key technologies are listed in Apx Table C.1 and Apx. Table C.2 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.

Apx Table C.1 Assumed technology learning rates that vary by scenario

Technology	Scenario	Component	LR 1 (%)	LR 2 (%)	LR 3 (%)	References
Photovoltaics	Current policies	G	20	30	13	(IEA 2021, IRENA, 2023, Fraunhofer ISE, 2015)
Rooftop BOP		L	17.5	8.5	4.5	
Large scale BOP		L	17.5	17.5	17.5	
Photovoltaics	Global NZE by 2050	G	20	30	23	
Rooftop BOP		L	17.5	17.5	8.5	
Large scale BOP		L	17.5	17.5	17.5	
Photovoltaics	Global NZE post 2050	G	20	30	23	
Rooftop BOP		L	17.5	8.5	4.5	
Large scale BOP		L	20	10	10	
Electrolysis	Current policies	G	10	5	5	(Schmidt et al., 2017, IEA 2024b)
		L	8	8	8	

Electrolysis	Global NZE by 2050	G	18	18	9	
		L	8	8	8	
Electrolysis	Global NZE post 2050	G	10	5	5	
		L	8	8	8	
Ocean	Current policies	G	10	5	5	(IEA, 2021)
	Global NZE by 2050	G	20	10	10	
	Global NZE post 2050	G	14	7	7	
Fixed offshore wind	Current policies	G	10	5	5	(Samadi, 2018; Zwaan, et al. 2012; Voormolen et al. 2016; IEA, 2021)
Fixed offshore wind	Global NZE by 2050	G	20	10	10	
Fixed offshore wind	Global NZE post 2050	G	15	8	8	
Floating offshore wind	Current policies	G	10	5	5	
		G	10	5	5	
Floating offshore wind	Global NZE by 2050	G	20	10	10	
		G	20	10	10	
Floating offshore wind	Global NZE post 2050	G	15	8	8	
		G	15	7.5	7.5	
Utility scale energy storage – Li-ion	Current policies	G	7.5	7.5	7.5	(Grübler et al., 1999; McDonald and Schrattenholzer, 2001)
		L	7.5	7.5	7.5	
Utility scale energy storage – Li-ion	Global NZE post 2050	G	10	10	10	
		L	10	10	10	
Utility scale energy storage – Li-ion	Global NZE by 2050	G	15	15	15	
		L	15	15	15	
Onshore wind	Current policies	G	4.3	4.3	4.3	(IEA, 2021; Hayward & Graham, 2013)
		L	9.8	4.8	2.8	
	Global NZE post 2050	G	4.3	4.3	4.3	

		L	9.8	4.8	2.8	
	Global NZE by 2050	G	4.3	4.3	4.3	
		L	11.3	11.3	11.3	

While solar photovoltaics are implemented with separate learning rates for large scale and rooftop balance of plant (BOP), inverters are not included in the BOP nor 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 inputs from GHD (2025) to ensure costs represent Australian project costs. 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.

Apx Table C.2 Assumed technology learning rates that are the same under all scenarios

Technology	Component	LR 1 (%)	LR 2 (%)	LR 3 (%)	References
Coal, supercritical	-	-	-		
Coal, ultra-supercritical	G	2	2	2	(IEA, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	20	10	5	(EPRI 2010; Rubin et al., 2007)
	L	20	10	5	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Gas peaking plant	-	-	-		
Gas combined cycle	-	-	-		
Nuclear	G	-	-		(IEA, 2008)
Nuclear SMR	G	20	10	5	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Diesel/oil-based generation	-	-	-		
Reciprocating engines	-	-	-		
Hydro and pumped hydro	-	-	-		
Biomass	G	5	5	5	(IEA, 2008; Neij, 2008)
Concentrating solar thermal (CST)	G	14.6	7	7	(Hayward & Graham, 2013)
	L	14.6	7	7	

CHP	-	-	-		
Conventional geothermal	G	8	8	8	(Hayward & Graham, 2013)
	L	20	20	20	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Fuel cells	G	20	10	10	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Steam methane reforming with CCS	G	20	10	5	(EPRI, 2010; Rubin et al., 2007)
	L	20	10	5	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)

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 and storage given that these technologies tend to be lower cost and crowd out opportunities for competing low emission technologies. Apx. Figure C.1 shows the learning rates by scenario for solar PV, electrolysis, ocean energy (wave and tidal), offshore wind, batteries and pumped hydro. The remainder of learning rate assumptions, which do not vary by scenario are shown in Apx. Table C.2.

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 global trends (see Appendix D). As discussed in Appendix D, Australia has had a flat onshore wind capacity factor trend and so these global assumptions do not apply to Australia. The capacity factor for floating offshore wind is assumed to be 5.6% higher than that of fixed offshore wind, based on an average of values (Wiser et al., 2021). Capacity factors for offshore wind are assumed to improve in Australia in line with the rest of the world.

C.2 Electricity demand and electrification

Various elements of underlying electricity demand are sourced from the World Energy Outlook (IEA, 2021; IEA, 2022; IEA, 2023). Demand data is provided for the Announced Pledges scenario, 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.

C.2.1 Global vehicle electrification

Global adoption of electric vehicles (EVs) is projected using an adoption curve calibrated to correspond to Global NZE by 2050 scenario from the IEA World Energy Outlook. The shape of the adoption curve varies by vehicle type, where cars and light commercial vehicles (LCV) have faster rates of adoption, followed by medium commercial vehicles (MCV) and buses. The adoption rate is applied to new vehicle sales shares.

C.3 Hydrogen

In GenCost projections prior to 2022-23, 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 Proton Exchange Membrane (PEM) electrolysers. That is, we have a single electrolyser technology. The approach reflects the fact that GALLME is not temporally 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 2050 are shown in Apx. Table C.3 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.

Apx Table C.3 Hydrogen demand assumptions by scenario in 2050

Scenario	Total hydrogen demand (Mt)
Current policies	132
Global NZE post 2050	274
Global NZE by 2050	366

C.4 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 fuel-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.

C.5 Resource constraints

The availability of suitable sites for renewable energy farms, available rooftop space for rooftop solar 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 (Apx. Table C.4) (see Government of India, 2016, Edmonds, et al., 2013 and Hayward and Graham, 2017 for more information on sources). With the exception of rooftop solar PV these constraints are removed in the Global NZE by 2050. Floating offshore wind has some technical limitations in regions, but these limitations are greater than electricity demand.

C.6 Other data assumptions

GALLME international black coal and gas prices are based on (IEA, 2023) 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 fuel prices must fall[26]. 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.

Apx Table C.4 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 %	CST %	Onshore wind %	Fixed 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

[26] 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.

Region	Rooftop PV %	Large scale PV %	CST %	Onshore wind %	Fixed offshore wind GW
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)

Power plant technology operating and maintenance (O&M) costs, plant efficiencies and fossil fuel emission factors were obtained from (GHD, 2025) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2023) (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) (Energy Information Administration, 2017a) (Energy Information Administration, 2017b) (GWEC) (IEA, 2016a) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015).

New capacity that was installed in 2023 was sourced from (IRENA, 2024) (Global Energy Monitor, 2024a) (Global Energy Monitor, 2024b) and (Global Energy Monitor, 2024c).

Appendix D Frequently asked questions

The following list of questions represents a summary of the most commonly asked questions in relation to methods and assumptions applied in GenCost.

D.1 Process

D.1.1 Why does GenCost not immediately change its report when provided with new advice from experts?

The GenCost report undertakes a significant stakeholder consultation process, but it is not a consensus process and the response to feedback is based on its quality, not who provided it. This process is consistent with the objectivity and scientific approach that stakeholders expect of CSIRO.

There have been suggestions from some stakeholders that because some information was provided by an expert or group of experts it should have been accepted and acted upon immediately. This is not sufficient grounds for making a change to the GenCost report. Changes to the GenCost report need to be based on public evidence and reason. They cannot be based on assertions alone, no matter the qualifications and experience of the individual or group of individuals providing input.

GenCost reserves the right to test the quality of any evidence provided. There are widely varying qualities of data and evidence provided in the consultation process. Stakeholders should consider the many issues that can impact the quality of evidence when providing it such as the appropriateness of methodologies used to develop the data, stated or unstated vested interests behind the data development, and the level of inherent proof the evidence represents (e.g., correlation versus causation, opinion versus verifiable data).

Finally, CSIRO reserves the right to prioritise the issues and evidence it chooses to investigate. Not every topic raised will be fully investigated in the year the feedback is received. We prioritise issues based on their relevance, the weight of feedback received, and the technical challenges associated with investigating the topic in a way that meets our own standards.

D.2 Scenarios

D.2.1 Why are disruptive events and bifurcations excluded from the scenarios?

It is acknowledged that the future evolution of major drivers of the global energy system will not be smooth, particularly considering the recent pandemic and Ukraine war impacts on the energy sector. GenCost provides relatively smooth projections of capital costs over time compared to what is likely to occur. This reflects our understanding that very few end-users of the capital cost projections would like to access results that include major discontinuities. More volatility in inputs will lead to more volatility in all model outputs. Such volatility can interfere with the interpretation of models which are often seeking to answer separate questions about the evolution of the system by reading into the changes in the modelling results. As such, our judgment is that adding more realism does not add value in this case.

D.2.2 Why is no sensitivity analysis conducted and presented?

The staff delivering GenCost have many decades of experience in energy and electricity system modelling. They understand which parameters in the model have the greatest impact on model outcomes. The scenarios have been designed to explore those parameters that are the most uncertain and impactful (within a plausible range) so that they provide a set of results that represent the likely range of outcomes. The possible range of outcomes is wider and could be calculated. However, our understanding of end-user needs is that they require outputs that align with globally accepted literature on the likely range of major drivers such as global climate policy, learning rates and resource constraints. Should our understanding of the likely range of any of these factors change, the scenarios will be updated.

D.3 Capital costs

D.3.1 What did you base your large-scale nuclear costs on?

The GenCost 2023-24 final report provides a detailed discussion of the method for estimating large-scale nuclear costs in Section 2.5

D.3.2 Why have the estimates for nuclear SMR capital costs increased so much since 2022?

The GenCost 2023-24 final report provides a detailed discussion of the history of estimating nuclear SMR costs in Section 2.4. This report has adopted the project cost for the Darlington nuclear SMR project as its primary source current and near term costs.

D.3.3 Do you assume Australia continues to rely on overseas technology suppliers or are you assuming Australia develops its own original equipment manufacturing capability?

The context of this question is the concern that reliance on overseas manufacturers makes Australia vulnerable to non-competitive market pricing (e.g., the dominance of China), delayed access to technology because of competing buyers or represents a security of supply risk in the event of conflict in or with supplying countries. In this context, some government policies have provided international partnership support and direct grants for critical minerals projects[27].

[27] https://www.industry.gov.au/publications/critical-minerals-strategy-2023-2030/our-focus-areas/2-attracting-investment-and-building-international-partnerships

Whilst GenCost will continue to monitor these developments, the equipment component of capital cost estimates remains based on the best available representative technology cost deployment in Australia with equipment supplied from anywhere in the world that meets our standards.

D.3.4 Why does GenCost persist with the view that technology costs will fall over time when there are many factors that will keep technology costs high?

In the GenCost 2022-23 final report, research was outlined that indicated that there is no historical precedence for the real cost of commodities increasing indefinitely in real terms. Most periods of high prices resolve themselves within 4 years. Longer-term commodity price super cycles do occur but are shallower and are associated with changes in global economic growth. There is no suggestion from stakeholders that the world is in a major economic growth cycle. It was also argued in GenCost 2022-23 that global manufacturing will not need to be endlessly scaled up. Rather global technology capacity forecasts indicate that technology manufacturing capacity will need to grow to 2030, but after that point will be able to meet mostly linear demand for additional capacity without significant additional scale-up.

Stakeholders have raised the following additional points on this topic:

- That the energy sector may have a different inflationary path to the economy in general
- That GenCost needs to prove that the world is not in a new commodity super cycle
- That concentration of manufacturing in China will lead to non-competitive behaviour and high prices for those products, particularly solar
- That demand for energy technologies will remain non-linear for a long time because of delays in Australian deployment.

The current uncertainty in global manufacturing is acknowledged and makes forecasting at this time in history very challenging. The global inflationary event triggered by the pandemic is a significant structural break. Based on the evidence available of similar events, the approach taken has been to assume a reasonably quicker resolution of high technology prices with some lingering effects for 3 to 6 years, the length depending on the scenario.

The data on technology project costs from GHD and various commodities price inputs to those technologies indicates (so far) that the evidence is in alignment with our approach. Some costs have already fallen in real terms. Some are still rising but the rate of increase is significantly lower. The evidence from GHD (2025) points to cost pressures easing. Commodity price reporting also indicates cost pressures have eased in raw material markets such as lithium.

Based on this data, it does not appear energy is on a different path to the rest of the economy. Solar panels produced predominantly by China who have market power are recovering better than others and their price increase was more modest to begin with.

Regarding the expected linear growth rates in technology deployment, this refers to the global technology deployment and the required global manufacturing capacity to meet this growth. Australia's technology deployment rate, while important to us as Australians, has very little impact on the scale or cost of global technology manufacturing.

Notwithstanding these points, our projection methodology assumes increasing land and installation costs (in real terms). These exceptions are due to the scarcity of land and suitably qualified construction labour. This assumption means that the costs of some technologies (particularly mature technologies) increases for significant parts of the projection period.

D.3.5 Why is the uncertainty in the data not emphasised more?

GHD (2025) provide an uncertainty range of +/- 30% for their capital costs. To reduce this uncertainty, their analysis would have to be performed on a specific project. The GenCost project requires general data, not specific project data, that can be used in national level modelling studies. GHD (2025) also provide factors to convert the general costs to specific locations in the National Electricity Market (NEM). In that context, GenCost data is based on transporting and installing equipment not more than 200km from Melbourne but can be converted to other locations. An important aspect for GenCost is that all data is on a common basis.

Some stakeholders have requested that we emphasise this uncertainty in capital costs more in the text and diagrams. The main purpose of GenCost has always been to provide data which can be used in modelling studies. While there are stochastic modelling frameworks, the majority of electricity system models used in Australia are deterministic. In simple terms, this means they use single data points without any probability information attached to them. Therefore, GenCost capital cost outputs, which focus on providing scenarios to explore uncertainty rather than probability ranges, remain appropriate for the end-use they are created for.

LCOE data is specifically designed for the non-modelling community. In this case, we take a different approach. LCOE data is always presented as a range representing the plausible maximum and minimum costs. We also provide ranges for key inputs to the LCOE calculations such as capital costs, fuel costs and capacity factors.

D.3.6 Why include an advanced ultra-supercritical pulverised coal instead of cheaper, less efficient plant designs?

Some stakeholders take a view that although Australia has national and state net zero emissions policies by 2050, the highest greenhouse gas emitting options should remain on the table. The deployment of new coal has low plausibility given its high emissions intensity. A high efficiency design brings it closer to being plausible by reducing its emissions. Perhaps the most plausible scenario for building new coal consistent with meeting the net zero emissions by 2050 target would be to later retrofit coal generation with carbon capture and storage. Carbon capture and storage imposes a very significant fuel efficiency loss on the coal generator. In this context, it is even more important to start from a high efficiency coal generation technology.

D.4 LCOE

D.4.1 Why is the economic life used in LCOE calculations instead of the full operational life?

The LCOE calculation converts all upfront and ongoing costs to annual costs which is then divided by annual production. The capital cost component of a technology is converted to an annual repayment to the debt and equity providers. The annual repayment amount is determined using the economic life and the weighted average cost of capital. The economic life is shorter than the asset life for some technologies such as coal, nuclear and hydro. Some stakeholders have queried why this is so.

Debt and equity providers require a shorter payback period than the total asset life for some technologies to avoid the risk that part of the equipment might fail or might need new investment (sometimes called refurbishment or extension costs) to keep operating safely and reliably. To determine the economic life, debt and equity providers might look to the warranties provided with the equipment. They might also look at the typical timing of refurbishments or life extensions for that technology. The economic life is an input provided by the engineering firm that AEMO commissions each year as an input to GenCost.

Some stakeholders suggested that coal and nuclear could access special financing arrangements to move the economic life closer to the asset life. However, our preference is not to introduce special arrangements for technologies where there is limited Australian evidence. A common approach to the LCOE calculation is important to maintain comparability. The 2024-25 report does explore the impact of longer capital recovery periods in Section 2. It finds there is no significant benefit from the longer operational life of nuclear relative to shorter-lived technologies whose costs have been falling over time.

Determining the economic life of storage is more complex because the cycle life comes into play in determining the life of some components. The cycle life and intended use of the storage device might also be something debt and equity providers are also interested in to set the repayment date. Batteries in GenCost are costed for a project which has purchased a 20-year warranty on the battery (this warranty is costed as part of the ongoing operating and maintenance cost – see GHD (2025) for more information on this).

It should also be noted that cycle life is often calculated in the academic literature based on a full charge and discharge and is tested over a shorter period than would occur in practice. It is not clear how well deployed storage projects will match the lab tests. Their operation may be more prone to partial discharge, preferring to save some charge for higher priced periods. That is, they will bid parts of their storage capacity at different prices. Time will tell how this bidding behaviour will impact their cycle life, but it is a reasonable expectation that practical operation will be less damaging to batteries than the lab tests.

D.4.2 Coal and nuclear plants are capable of very high capacity factors, why do LCOE calculations not always reflect this?

Stakeholders are sometimes not aware of the difference between the availability factor, which is how often a plant will be technically available to generate electricity and the capacity factor which is how often they typically generate electricity after the effects of competition or other market constraints which limit generation.

In the last ten years in Australia, baseload generators have had an average capacity factor of 59% (see Appendix D GenCost 2022-23 final report). The simple reason for this outcome is that most baseload plants need to reduce production at night and in milder seasons when demand is lowest. There are individual generators that do achieve around 90%. These are a minority of plants which have a fuel cost advantage which allows them to keep running at full production during low demand periods by underbidding other generators for the right to keep generating at a high level.

GenCost LCOE calculations allow for the fact that a new baseload generator might achieve a capacity factor of up to 89% based on the maximum achieved by black and brown coal generators. At the low end of the range a capacity factor of 53% is assumed for new black coal, brown coal or nuclear generators which is equivalent to achieving 10% below the average capacity factor for black and brown coal. Around 10% of nuclear generators globally run at less than 60% capacity factor and many have run at over 90%[28]. However, we prefer to use Australian data for the plausible baseload plant operation data because it is consistent with our electricity load curve while other countries may have very different loads. For example, some equatorial and northern regions with hotter and colder climates have higher rates of air conditioning in buildings leading to flatter electricity loads (where either electricity or combined heat and power are the energy source).

Higher penetration of renewables, which have a zero fuel cost, could make it difficult for new baseload plant to achieve high capacity factors depending on the scale of demand overall. Ultimately, we do not know what new coal or nuclear will be competing with in the future. The key principle though is to acknowledge a plausible range rather than assume only the best outcome for new build capacity factors.

D.4.3 Why do LCOE calculations not use the lowest historical capacity factors for the low range assumptions?

For all existing technologies there are some generators that are performing poorly relative to what might be expected, and these represent the low range of historical capacity factors which were examined in Appendix D of the GenCost 2022-23 report. The data does not reveal why some projects are performing below expectations, but it could represent older technologies or, for renewables, sites that did not live up to expectations in terms of the renewable resource. GenCost LCOE capacity factor low range assumptions are developed on the basis that new entrant technologies will not be deployed if they cannot perform close to the current average capacity factor performance. Investors would prefer to avoid such projects in preference for more

[28] https://world-nuclear.org/our-association/publications/world-nuclear-performance-report/global-nuclear-industry-performance

attractive investment options. Accordingly, we apply a common rule across renewables, coal, nuclear and gas that the minimum capacity factor for new plant is 10% below the previous ten years average capacity factor for that technology or its nearest equivalent grouping (baseload technologies are treated as one group).

D.4.4 Why were all potential cost factors not included in the LCOE calculations?

While each technology has its own specific characteristics the goal of the LCOE calculation is to use a common formula to calculate costs so that that observed differences in costs are due to a small set of key differences in the technology, namely: capital costs, fuel costs, fuel efficiency, operating and maintenance costs, economic life and construction time. However, often stakeholders request that other special topics be included in the calculations. Items requested to be added to the LCOE analysis by stakeholders include:

- Plant decommissioning and recycling costs
- Deeper pre-development costs
- Technology degradation
- Whole-of-life emissions
- Savings from developing on a brownfield site
- Various environmental impacts
- Energy in manufacturing costs
- Public acceptance barriers
- National security impacts
- Extreme climate events
- Connection costs
- Marginal loss factors.

Adding these additional parameters would greatly expand the physical and time boundary of the generic generation projects assumed in GenCost and require more complicated formulas to implement. Our current understanding is that few of the topics presented in the feedback have a large enough impact on LCOE to warrant a change in the boundary or formula. That is, it would add complexity and cost to the project without significantly changing the outcome of the comparisons. Some factors, like marginal loss factors are significant but are too unpredictable at this stage of the energy transition.

We do acknowledge that taking account of brownfield project characteristics would make a difference in costs. This is because brownfield projects can avoid some development costs associated with site selection, grid connection and land. However, brownfield projects are outside our stated scope for GenCost of greenfield or new build projects. The study of brownfield projects is always site-specific and more resource intensive and for these reasons less generally comparable to other options. Their inclusion would essentially amount to bringing “one-off” projects into the analysis. This is inconsistent with our goal of providing a general comparison metric. Some brownfield project costs are included in AEMO’s publicly accessible forecasting input data.

There are two exceptions in the past where GenCost added new technology cost elements. These are CO_2 storage costs for carbon capture and storage technologies and integration costs for variable renewables. In both cases, the impact of these additional elements is significant and justifies modification of the standard approach to LCOE calculation.

Given that GenCost does not account for all potential additional project costs such as those captured in the list above, real projects are likely to cost more than indicated by the LCOE. Consequently, investors must do their own deeper studies to discover these. Likewise, investors who are interested in brownfield project development will need to source this information elsewhere (e.g., check AEMO publications) or do their own analysis.

Energy used in manufacturing costs are accounted for in capital costs. Notwithstanding the current difficulties in manufacturer profitability following the global supply chain crunch, to remain solvent, manufacturers must recover these costs (as with all other costs), in the long term, by building them into their technology prices. Also, the more that global economies track and potentially price greenhouse gas emissions, the greater the incidence of lifecycle greenhouse gas emissions of projects being built into technology prices. Planned carbon border adjustment mechanisms are an example of this.

D.4.5 What is the boundary of development costs? Is it only costs from the point of contracting a developer before commencing construction?

GHD's reports and data break down the capital cost into three components: equipment, land and development and installation costs. Development costs are captured in the land and development segment. GHD (2025) provides this definition of the land and development cost component:

"*The development and land costs for a generation or storage project typically include the following components:*

- *Legal and technical advisory costs*
- *Financing and insurance (no interest during construction considered)*
- *Project administration, grid connection studies, and agreements*
- *Permits and licences, approvals (development, environmental, etc)*
- *Land procurement and applications."*

D.4.6 How is interest lost during construction included in GenCost?

The type of capital cost data included in GenCost is called overnight capital costs. That is, it is the cost if you built it overnight. Consequently, to make the costs more realistic, interest lost during the construction period needs to be added when using this data.

Interest lost during construction is added differently depending on how the data is being used. When overnight capital cost data is being used in an energy system model, information is provided to the model about the construction time. The time discounting function within the system model accounts for the interest lost during construction in the time delay between investment expenditure and when the project is fully operational.

When overnight capital cost data is being used in an LCOE calculation a different approach is used. LCOE calculations must average all costs into a single year of electricity production and so the time during construction does not exist as a concept. However, there are several ways in which the interest lost can be added to an LCOE. GenCost uses the simplest way which is to increase the capital cost by the assumed discount rate raised to the power of the construction time[29]. There are more sophisticated ways to do this which account for developer plans for drawing down the financing during construction depending on the arrival time of different plant parts and payment for each component. These more detailed approaches are appropriate for real project planning but require tailored calculations for each technology and a cash flow model approach. The cashflow approach tracks payments over each year of construction plus economic life before averaging them into a single yearly cost (dividing total expenditure including the construction period by total production including periods of zero production during the construction period). The simpler approach is more efficient (requires just a few cells of calculations and fewer input data), but the latter is more accurate. The simpler approach tends to overestimate interest lost during construction as it assumes all funds need to be drawn down at the beginning of construction.

D.4.7 Why are the cost of government renewable subsidies not included in the LCOE calculations for variable renewables with integration costs?

The cost of government subsidies for variable renewables, in whatever form they take, are not included as a cost because all of the variable renewable costs applied in the modelling are without subsidy. In other words, because we do not subtract any subsidies from the cost of variable renewable generation, it is not necessary to add those subsidies back in as a cost to society. The GenCost estimates of the cost of integrating variable renewables are without any government subsidies.

D.4.8 Why is a value of 100% applied to the fuel efficiency of renewables in the LCOE formula?

For our purposes there is no practical limit to supply of solar and wind power and its cost as a fuel is free. Since the fuel price applied is zero, any value for renewable energy efficiency other than zero would work in the fuel cost formula (and avoid division by zero) where fuel cost equals FuelPrice÷FuelEfficiency. We choose 1 or 100% for simplicity. This is not to say that the energy conversion efficiency of renewable generation technologies is 100%, or irrelevant, or not accounted for. The conversion efficiency of solar irradiance and wind to electricity is accounted for in the capital cost. Manufacturers apply a nameplate plant capacity in watts to the equipment they sell based on exposure to representative wind speeds or solar irradiance and this reflects the energy conversion efficiency of the plant. Conversion efficiency is also partially captured in land costs which reflect the scarcity of sites with the required renewable resources to operate at nameplate capacity.

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[29] GenCost readers who have downloaded the Appendix tables from CSIRO's Data Access Portal should be able to find this step in the cell formula under the Capital component of the LCOE calculation

D.4.9 Why do you apply only one discount rate or weighted average cost of capital to all technologies?

This question may arise in the context of stakeholder concerns that some projects might be government funded and receive a lower financing rate and that should be included. While GenCost recognises that governments have in the past and may choose in the future to provide lower cost financing to selected projects, GenCost makes no specific assumptions about who will invest in a technology project.

Another factor guiding our approach is that we wish to compare technologies on a common basis wherever that approach does not lead to an unwanted distortion. In most cases, that can be achieved but there are exceptions. In some cases, we need to apply a different formula or method to different technologies to capture important additional costs such as adding reliability costs for variable renewables or carbon dioxide storage costs for CCS technologies (see D.4.4 for a longer discussion of what additional costs we have chosen to include).

Previous versions of GenCost also applied a cost of capital premium to fossil fuel technologies due to their additional climate policy risk. However, our judgement was that although that risk is real and ongoing, we were no longer able to find a cost of capital premium that adequately captured that risk. Instead, wherever we present high emission fossil fuel technology costs we simply state that investment in these technologies may not be consistent with government emission targets.

In conclusion, our judgment is that, in the case of the cost of capital, applying the same rate to every technology is the most informative and least distortionary approach for levelised cost of electricity. Other modelling exercises may take an alternative approach. However, our LCOE data is not likely to be an input to any detailed electricity system modelling. Rather LCOE data is simply an indicator of the potential direction of the results from more detailed modelling.

D.4.10 Why did you take the maximum and average of existing generator prices to create the high and low range new build coal prices?

Our goal is to explore the high and low range for total coal generation costs in the LCOE calculations. To do this we include high and low ranges for the various inputs to coal generation costs such as capacity factors, capital costs and coal fuel costs.

We require coal prices for new-build projects which are different to coal prices that are received by existing generation sites. Some existing generators receive low coal prices because they may have captured an adjacent coal mine with no competing rail line to export markets. Alternatively, if they are competing with export markets, they are more likely to have developed a favourable long-term contract to manage high price risk. New-build projects will start their life by competing with export markets for supply of coal.

High and low coal prices are sourced from the AEMO Inputs and Assumptions workbook. The June 2022 Inputs and assumptions workbook provided coal prices for new build and existing coal generators. Reflecting the issues discussed above, average new build coal prices were two and half times higher than the minimum existing generator coal prices. For GenCost 2022-23, our methodology for selecting coal prices to use in GenCost was to take the minimum and maximum of only the new build coal prices.

After June 2022, AEMO has no longer published new build coal prices. This reflects the bipartisan policies of net zero emissions by 2050 which make it unlikely that new coal can be developed in Australia. AEMO continued to publish coal prices, but only for existing generators which remain in the system.

To create the high and low range for new build coal prices post-2022-23 GenCost had to apply a new methodology based on the only available data which was coal prices for existing generators. Knowing that new build coal prices are at least as high as that for existing generators, for the maximum, GenCost simply takes the maximum of existing generator prices.

However, for the minimum new build coal prices, taking the minimum of existing generator prices is not appropriate. CSIRO developed a new methodology, using the only available data from AEMO on coal prices for existing generators, to extrapolate the low-cost range. This methodology takes into account that new-build coal generation projects cannot achieve the same low prices as existing generators, hence why the low coal prices are averaged. The average of the lowest coal price trajectory for existing generators tends to be two to three times the minimum coal price for those generators, which maintains the previously observed relationship between existing generator and new build coal prices.

IEA coal prices are used in the global modelling which underpins the capital cost projections. A different source is justified on the basis that the global modelling requires a consistent set of global fuel prices by major global region which is not available from AEMO which only provides Australian data.

D.4.11 Why do you not include high and low ranges for economic life?

Economic life is in some cases set by a warranty. This is the case for batteries. In other cases, it represents long standing practice in the financing of utility assets which are unlikely to vary significantly between Australian projects. While many stakeholders have provided evidence for variation in asset lives, there has been little evidence provided on variation in economic life or warranties or loan periods. At this stage, there is not enough information to form a basis for a high and low range for economic life as an input to the LCOE calculations. See D.4.1 for a discussion on the differences between economic and asset life.

D.4.12 Why are your low range capacity factors for coal and renewables closer to the historical average capacity factor?

In the GenCost 2022-23, report capacity factors from the previous ten years were reviewed to inform our choices about capacity factors in the LCOE calculations. Stakeholders have noted that the low range capacity factor applied is close to the ten-year average capacity factor. In fact, the approach to set the low range value for new-build generators is to use a value 10% below the average capacity. Our reasoning is that new projects are less likely to proceed if their capacity factor is significantly lower than the market average. The same method is applied for renewables as for coal to develop the low range capacity factor assumption.

For the high capacity factor assumption, the highest capacity factor achieved over a ten year period is applied. Given these are new-build, it is appropriate to be less conservative on the high range assumption. Again, the approach is the same for coal and renewables.

D.4.13 If GenCost shows renewables are cheaper, why are electricity prices higher in Australia and in countries transitioning to renewables?

GenCost calculates the breakeven cost of electricity needed for investors to recover their capital, fuel and operating costs, including a reasonable return on investment. This is an indicator of the electricity price needed to encourage new investment, but it does not control the electricity price. Electricity prices are controlled by the balance of supply and demand. If supply is tight relative to demand, then prices go up. If supply is significantly more than demand, then prices go down. Changes in fossil fuel prices are another source of volatility. Price increases in recent years are a combination of lack of supply and fuel price volatility.

In 2022, global natural gas supply constraints, triggered by sanctions on Russia due to the Ukraine war, together with unplanned coal plant outages caused a price spike in Australia that is still reverberating through the electricity system. The prices of other electricity systems around the world were also impacted by the rising global fossil fuel prices and constrained supply of gas.

In Australia, retailers, experiencing these conditions, secured electricity supply contracts for 2023-24 and factored these higher prices in. A decrease in gas prices or growth in new supply capacity (net of retirements) can put downward pressure on market prices. However, there is no guarantee that either of these forces will maintain downward pressure on prices. If gas prices rise again or capacity is retired faster than it is rebuilt, then prices will increase again regardless of the cost of new entrant capacity.

The quality of both renewables and fossil fuel resources varies substantially around the world as do the pace of transition to lower emission sources, the degree of state ownership, subsidies, age of generation fleet and market incentives for building new capacity. As a result, due to the variety of differences in circumstances and the impact of supply and demand imbalances, there are no clear causal relationships that can be concluded from a simple correlation analysis of electricity prices and the energy source used by country or region.

D.4.14 If nuclear has such high capital costs why do they have such low-cost nuclear electricity overseas?

New large-scale nuclear costs are significantly lower than nuclear SMR but both represent moderate- to high-cost sources of electricity generation. This result could be perceived as out of step with overseas experience where some countries enjoy low-cost nuclear electricity. There are two reasons for this seemingly inconsistent result.

The first is that new generation technology electricity costs have only weak transferability between countries. While the technology can be identical, electricity generation costs vary widely between countries due to differences in installation, maintenance and fuel costs in each country. There are also unknown or known subsidies and different levels of state versus private ownership which impact the costs that ultimately get passed to electricity customers.

The second issue is that observations of low-cost nuclear electricity overseas are in most cases referring to historical rather than new projects which could have been funded by governments or whose capital costs have already been recovered by investors. Either of these circumstances could mean that those existing nuclear plants are charging lower than the electricity price that would be required to recover the costs of new commercial nuclear deployment. Such prices are not available to countries that do not have existing nuclear generation such as Australia.

In summary, given overseas new generation electricity costs are not easily transferable and may be referring to assets that are not seeking to recover costs equivalent to a commercial new-build nuclear plant, there may be no meaningful comparison that can be made between overseas nuclear electricity prices and the costs that Australia could be presented with in building new nuclear.

Appendix E 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 have been established to provide the project with more guidance on considerations for including technology options.

E.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 PV, 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.

E.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 publications and 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.

E.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 E.1 Examples of considering global or domestic significance

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
No	Yes	None currently. A previous example was **enhanced geothermal,** but domestic interest in this technology declined
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**)

E.4 Input data quality level is reasonable

Input data quality types generally fall into five 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, if a technology is included 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 paper studies are used. Confidential data as a primary information source is not used since, by definition, it cannot be validated by stakeholders. However, confidential sources could provide some guidance in interpreting public sources.

E.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 and single axis tracking solar PV over flat).

The approach to a technology’s specificity may be reviewed (e.g., two sizes of gas turbines have been added over time and offshore wind turbines have been split into fixed and floating). 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 are similar.

Shortened forms

Abbreviation	Meaning
AAS	Australian Academy of Science
A-CAES	Adiabatic Compressed Air Energy Storage
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
ATSE	Academy of Technological Sciences and Engineering
BAU	Business as usual
BOP	Balance of plant
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CIS	Capacity Investment Scheme
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated solar thermal
EV	Electric vehicle
FOAK	First-of-a-kind
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
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
ISP	Integrated System plan

Abbreviation	Meaning
kW	Kilowatt
kWh	Kilowatt hour
LAES	Liquid Air Energy Storage
LCOE	Levelised Cost of Electricity
SLCOE	System Levelised Cost of Electricity
LCOS	Levelised cost of storage
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
MLF	Marginal Loss Factor
Li-ion	Lithium-ion
LR	Learning Rate
Mt	Million tonnes
MW	Megawatt
MWh	Megawatt hour
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NOAK	Nth-of-a-kind
NSW	New South Wales
NT	Northern Territory
NZE	Net zero emissions
O&M	Operations and Maintenance
OECD	Organisation for Economic Cooperation and Development
PEM	Proton-exchange membrane
PHES	Pumped hydro energy storage
PV	Photovoltaic
REZ	Renewable Energy Zone
SMR	Small modular reactor
STEPS	Stated Policies Scenario
SWIS	South-West Interconnected System

Abbreviation	Meaning
TWh	Terawatt hour
UAE	United Arab Emirates
USC	Ultra-supercritical
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEM	Western Electricity Market
WEO	World Energy Outlook

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