Australia's National Science Agency

GenCost 2023-24

Final report

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Acknowledgements

This report incorporates feedback received from stakeholder input following the publication of a consultation draft in December 2023. The authors greatly appreciate the time stakeholders have given to support the project. We continue to rely on the collective deep expertise of the energy community to review GenCost to improve its quality.

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, in broad terms, world leaders continue to provide their support for collective action limiting global average temperatures. 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 costs of electricity generation, energy storage and hydrogen production with a strong emphasis on stakeholder engagement. GenCost represents Australia's most comprehensive electricity generation cost 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 electricity costs change significantly each year. This is the sixth 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 Aurecon. Based on these updated current capital costs, the report provides projections of future changes in costs consistent with updated global electricity scenarios which incorporate different levels of achievement of global climate policy ambition. Levelised costs of electricity (LCOEs) are also included and provide a summary of the relative competitiveness of generation technologies.

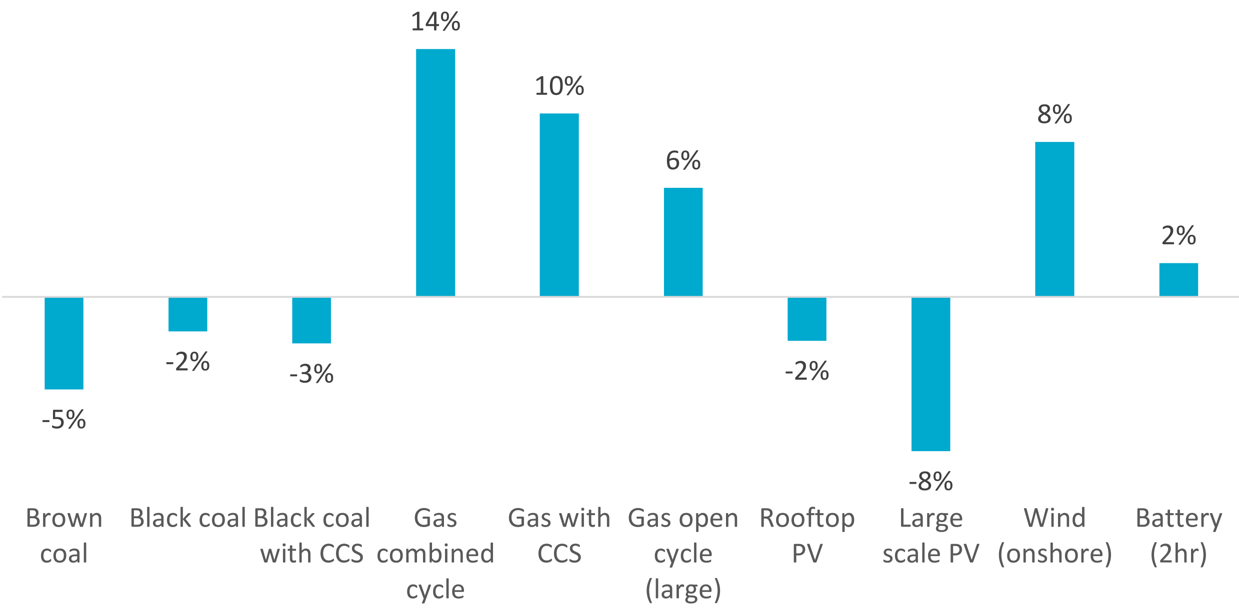
Outcomes of 2023-24 consultation

GenCost received the highest volume of feedback to the consultation draft in its history with 45 written submissions and many participating for the first time. This input has led to several changes, the most significant of which being the inclusion of large-scale nuclear in the report for the first time. GenCost has also increased wind generation costs and developed a revised approach for including solar thermal generation costs on a common basis with other bulk supply technologies.

Consultation continues to be a valuable way of improving the quality of the report given that no single organisation can cover the breadth of technologies explored. Feedback can take the form of suggestions and questions. Given the volume of feedback it has not been possible to individually address every question raised in the body of this report. However, we have now added Appendix D which addresses the major common questions and answers.

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 in freight costs. Consequently the 2022-23 GenCost report observed an average 20% increase in technology costs. One year on, the inflationary pressures have considerably eased but the results are mixed. The capital costs of onshore wind generation technology increased by a further 8% while large-scale solar PV has fallen by the same proportion. Gas turbine technologies were the other main group to experience cost increases of up to 14% (ES Figure 0-1). The capital costs of other technologies were relatively steady. Technologies are affected differently because they each have a unique set of material inputs and supply chains.



ES Figure 0-1 Change in current capital costs of selected technologies relative to GenCost 2022-23 (in real terms)

Addition of integration costs for variable renewables in 2023

Solar PV and wind are called variable renewables due to their weather dependency. The 2023-24 GenCost report includes integration costs for variable renewables in 2023 for the first time and incorporates it in the LCOE. Most new-build technologies can enter an electricity system and provide reliable power by relying on existing capacity. Existing capacity can provide generation at times when the new plant is not available or when demand is rising but the new-build technology is already at full production. This includes new-build variable renewables when they are in the minority. However, as their share increases, forcing the retirement of existing flexible capacity, the system will find it increasingly difficult to provide reliable supply without additional investment.

To address this issue, GenCost calculates the additional cost of making variable renewables reliable at shares of 60%, 70%, 80% and 90%[1]. We call these additional costs the integration costs of variable renewables and they consist mainly of additional storage and transmission costs.

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[1] 90% is about as high as variable renewable deployment is likely to need to go as increasing it further would result in the undesirable outcome of shutting down existing non-variable renewable generation from biomass and hydroelectric sources.

Feedback from the 2022-23 GenCost report requested that integration costs be presented that account for storage and transmission projects that will be delivered before 2030 since they have been sponsored by government or approved by the relevant regulator on the basis that they will be needed to support variable renewables. To accommodate that request, we present variable renewable integration costs for 2023 which include committed and under construction pre-2030 storage and transmission projects. 2030 LCOE results are also included but continue to exclude these pre-2030 costs since by 2030 they will represent existing capacity.

The results indicate that the cost of deploying high VRE shares is 12% to 36% higher in 2023 than in 2030. Around two thirds of the higher costs are due to investors having to pay 2023 instead of 2030 technology costs. Technology costs are falling over time. The remainder of the difference is due to the cost of the pre-2030 committed and under construction storage and transmission projects. Total integration costs to make high shares of variable renewables reliable are estimated at $41/MWh to $49/MWh in 2023 and $28 to $53/MWh in 2030 depending on the VRE share.

Addition of large-scale nuclear to GenCost

A majority of submissions to the 2023-24 consultation process requested the inclusion of large-scale nuclear in addition to nuclear small modular reactors (SMR) that had been included in GenCost since its inception in 2018. In response GenCost re-examined the appropriateness of large-scale nuclear and concluded that, although the deployment of large-scale nuclear would require a significant increase in the reserve margin relative to SMR and existing Australian generation plants, there was no known technical constraint to deploying generation units of this size. It was also concluded, due to the current state of the development pipeline in Australia, that the earliest deployment would be from 2040.

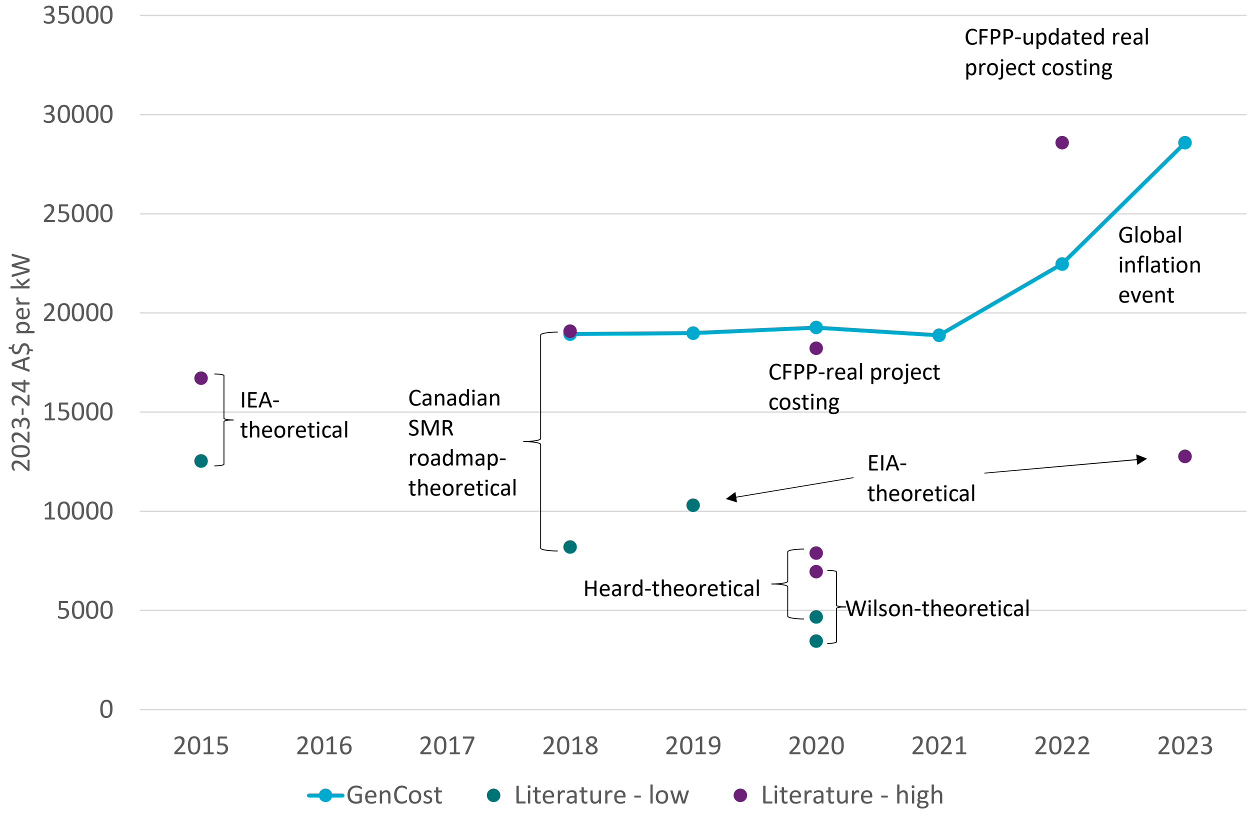
To source appropriate large-scale nuclear costs for Australia, it is necessary to rely on costs of large-scale nuclear deployed in other countries. Such costs are not directly transferable to Australia due to differences in a multitude of factors including labour costs, workforce skills, governance and standards. The source country for large-scale nuclear cost data also has to be carefully selected because there are large differences in costs between countries. The lowest costs occur in countries such as South Korea which has delivered a continuous building program for many years and costs are generally higher in western countries which have tended to have more sporadic building programs.

GenCost based its large-scale nuclear cost on South Korean costs as the best representation of a continuous building program consistent with other technologies in the report. GenCost then adjusted for differences in Australian and South Korean deployment costs by studying the ratio of new coal generation costs in each country. That ratio is used to scale the South Korean large-scale nuclear costs to Australian deployment costs. Based on this approach the expected capital cost of a large-scale nuclear plant in 2023 is $8,655/kW. This capital cost can only be achieved if Australia commits to a continuous building program and only after an initial higher cost unit is constructed. The first unit of all first-of-a-kind (FOAK) for Australia technologies are expected to be impacted by higher costs. This applies as much to nuclear as it does to other technologies such as offshore wind, solar thermal and carbon capture and storage. FOAK premiums of up to 100% cannot be ruled out.

The estimated electricity cost range for large-scale nuclear under current capital costs and a continuous building program is $155/MWh to $252/MWh. This is expected to fall by 2040, after current inflationary pressures resolve, to $136/MWh to $226/MWh.

Significant increase in nuclear small modular reactor costs

The cost of nuclear SMR has been a contentious issue in GenCost for many years with conflicting data published by other groups proposing lower costs than those assumed in GenCost (ES Figure 0-2). UAMPS (Utah Associated Municipal Power Systems) is a US regional coalition that develops local government owned electricity generation projects. Up until the project's cancellation in November 2023, UAMPS was the developer of a nuclear SMR project called the Carbon Free Power Project (CFPP) with a gross capacity of 462MW. It was planned to be fully operational by 2030. After conversion to 2023 Australian dollars, project costs were estimated in 2020 to be $18,200/kW which is only slightly below the level that GenCost had been applying ($19,000kW). This validated CSIRO's use of the higher end of the range presented in theoretical studies available at the time.



ES Figure 0-2 Timeline of nuclear SMR cost estimates (calendar year) and current costs included in each GenCost report (financial year beginning)

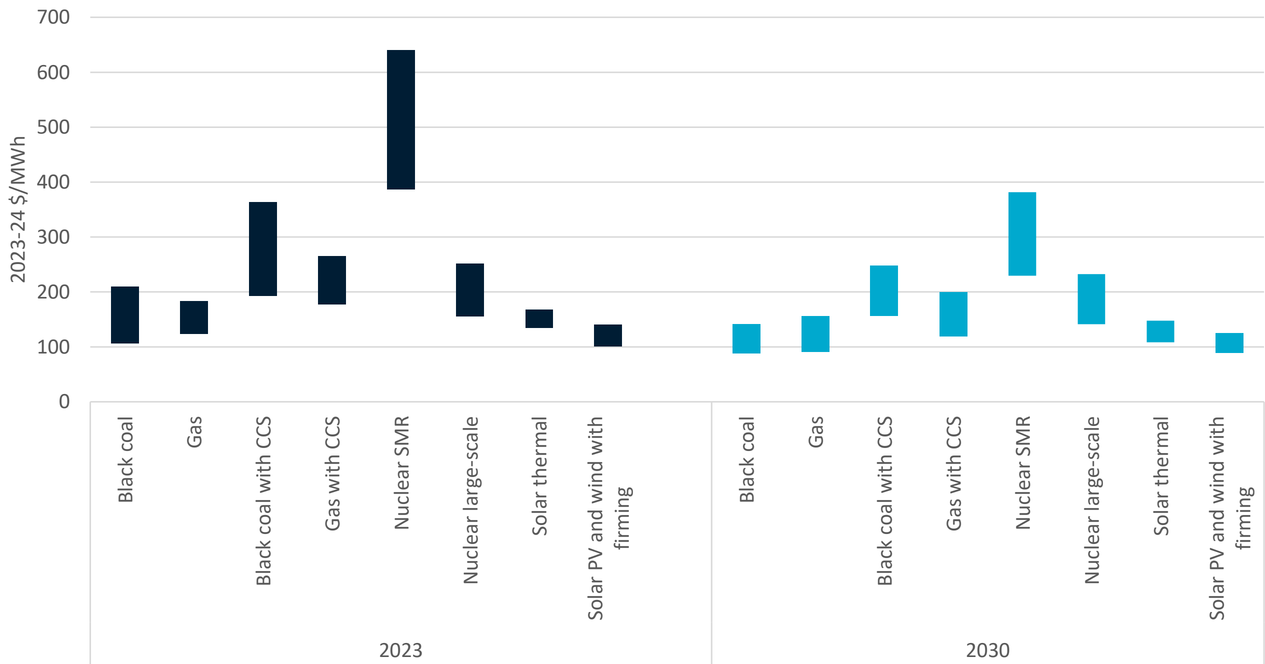
In late 2022 UAMPS updated their capital cost to $28,580/kW citing the global inflationary pressures that have increased the cost of all electricity generation technologies. The UAMPS estimate implies nuclear SMR has been hit by a 57% cost increase which is much larger than the average 20% observed in other technologies. This data was not previously incorporated in GenCost. Consequently, current capital costs for nuclear SMR in this report have been significantly increased to bring them into line with this more recent estimate. This new data is considered more reliable because all previous data was theoretical whereas the UAMPS project was the first to provide transparent data for a real project.

The cost of electricity technologies compared

LCOE is the total unit costs a generator must recover over its economic life to meet all its costs including a return on investment. Each input to the LCOE calculation has a high and low assumption to create an LCOE range for each technology (ES Figure 0-3).

The LCOE cost range for variable renewables (solar PV and wind) with integration costs is the lowest of all new-build technologies in 2023 and 2030. The cost range overlaps with the lower end of the cost range for coal and gas generation. These are high emission technologies which, if used to deliver the majority of Australia's power supply, are not consistent with Australia's current climate change policies[2].

If we exclude high emission generation options, the next most competitive generation technologies are solar thermal, gas with carbon capture and storage, large-scale nuclear and coal with carbon capture and storage.



ES Figure 0-3 Calculated LCOE by technology and category for 2023 and 2030

While solar thermal costs are low, given the need to access better solar resources further from load centres, they will face additional transmission costs compared to coal, gas and nuclear. Directly calculating these costs was not in scope but could add around $14/MWh to solar thermal costs based on transmission costs that were calculated for solar PV and wind.

Nuclear SMR costs improve significantly by 2030 but remain significantly higher cost than these other alternatives (ES Figure 0-3). For clarity, neither type of nuclear generation can be operational

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[2] Although most modelling indicates that gas is likely to continue to be utilised and constructed for some time yet as a peaking technology which supports the grid but with low contribution to total electricity produced. AEMO analysis of electricity systems consistent with net zero by 2050 can be accessed at: https://aemo.com.au/consultations/current-and-closed-consultations/draft-2024-isp-consultation

by 2030. Developers will need to purchase the technology in the 2030s sometime after an expected 11 years of pre-construction tasks are completed. 4 to 6 years of construction would then follow before full operation can be achieved. As such, the inclusion of large-scale and SMR nuclear in the 2030 cost comparison is only as a point of interest rather than practicality. Renewable and storage technologies also have development lead times, but their deep development pipeline of projects means that there are new projects reaching the point of financial close each year.

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 Aurecon (2024) and further information can be found in their report. The global scenario narratives and data assumptions for the projection modelling are outlined in Section 3. Capital cost projection results are reported in Section 4 and LCOE results in Section 5. CSIRO's cost projection methodology is discussed in Appendix A. Appendix B provides data tables for those projections which can also be downloaded from CSIRO's Data Access Portal[3]. 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. GenCost does not seek to describe the set of electricity generation and storage technologies included in detail.

1.1.1 CSIRO and AEMO roles

AEMO and CSIRO jointly fund the GenCost project by combining their own resources. AEMO commissioned Aurecon to provide an update of current electricity generation and storage cost and performance characteristics (Aurecon, 2023a). This report focusses on capital costs, but the Aurecon report provides a wider variety of data such as operating and maintenance costs and

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

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) 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, we have added an extra reporting year, 2023, for renewable integration costs reflecting strong interest in pre-2030 integration costs. The report also includes a longer discussion on large-scale and SMR nuclear costs given the significant current interest in this topic.

1.1.3 The GenCost mailing list

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

1.2 Feedback received from the consultation

The 2023-24 consultation report received the largest number of submissions since the project's inception in 2018. While the consultation has been mostly designed with an energy sector audience in mind reflecting the technical content of the GenCost report, the bulk of submissions were from individuals rather than energy sector companies, departments or associations.

Most individuals were making submissions for the first time and consequently several of the topics raised have been addressed in previous GenCost consultations. Reflecting on this development, GenCost will now include a permanent frequently asked questions section in the report so that stakeholders new to GenCost can check if their question has already been answered in past consultations. This is located in Appendix D .

The continued engagement of stakeholders is essential to ensure the ongoing improvement in the quality of the information and analysis in GenCost. In the following section the major changes or improvements arising from new stakeholder feedback are described. Minor changes are listed in less detail. Some feedback requested additional technologies or additional modelling and analysis that cannot be included in this year's report but could be considered in the future. All topics for future consideration are listed. This section is concluded with frequently asked questions which make up most of the discussion.

A number of submissions contained incorrect statements about GenCost content, methodologies, or purposes. These have not been directly listed or individually refuted here. Most of these statements appear to reflect a lack of familiarity with or misunderstanding of the detail of the report. GenCost continues to receive divergent submissions calling on one hand for more content, and on the other, a more streamlined, narrower scope. To improve readability, we have moved the data and assumptions to an appendix so that the report results are brought closer to the front.

Some feedback has been addressed simply by adding a sentence or paragraph of clarification in the report. For brevity, those changes have not been listed in this section.

A final category of feedback we are unable to address relates to questions where GenCost is being asked to affirm or deny the logic of a stakeholders' own analysis conducted in GenCost on renewable integration costs. To put this more colloquially, many submissions asked GenCost to check or refute their 'back of the envelope' calculations on renewable integration costs.

As discussed in Graham (2018) it is not possible to undertake spreadsheet type modelling to create a transparent but accurate estimate of the cost of integrating renewables. If it were, this would have been the preferred method of implementation in GenCost. Graham (2018) concluded an electricity system modelling approach must be applied, where the details of the calculations are written in code that call on proprietary optimisation algorithms which unfortunately results in a loss of transparency. In keeping with those findings, it is not appropriate for GenCost to provide technical support for stakeholders who want to pursue approaches that were previously assessed as potentially inaccurate or misleading.

In recognition of the interest amongst stakeholders in this topic, a future task has been added to determine if it is possible to provide a less complex open-source electricity model for exploring integration costs for variable renewables and other new-build technologies.

1.3 Changes made in response to feedback

There are a few major and several minor changes which have been implemented in this final report in response to feedback received during the consultation process. Below we also list requested changes that may be considered for future publications but were not included in this year's report due to lack of time, data or being considered a lower priority.

1.3.1 Major changes

Wind expected to experience longer delays in recovery from global inflationary pressures

In the 2023-24 consultation draft it was highlighted that technology costs were recovering from the global inflationary pressures of 2022 but that onshore wind had experienced the highest increase and slowest recovery. Wind generation prices were still rising in 2023-24 while solar PV costs fell in real terms. The difference in circumstances of the two most installed new-build generation technologies have been explained in various industry literature and stakeholder input as:

- A higher incidence of component failure in wind resulting in the need to replace components in the existing stock, presumably funded from either the revenue from new wind generation sales or higher insurance premiums which would increase the cost of wind generation manufacturing.

- Wind manufacturers continuing to push the technology envelope (e.g. size, height) and design for each regional deployment rather than focussing on a repeatable single design for all locations which is a more common approach for solar PV deployment.
- The longer lead times for wind project contracting and development meant that when inflationary pressures emerged, manufacturers had greater exposure to changes in supply chain costs.
- While both wind and solar PV had experienced a long period of high focus on cost reductions that meant margins were low, the wind sector was less able to manage the profit squeeze than solar PV due to higher component cost increases.

These experiences are expected to make wind manufacturers more careful about their share of exposure to supply chain risks, more focussed on repeatable designs that do not push the envelope and pricing that supports profit recovery. This suggests wind generation may be slow to deliver future real cost reductions.

There is a limit of course to how long each wind manufacturer can maintain or extend periods of higher prices. There is competition amongst western wind manufacturers and between manufacturers in the west and in China. There is also competition between solar PV and wind. Modelling tends to show that generation costs are lower when both wind and solar PV are deployed together as it reduces the amount of storage needed and transmission congestion through higher diversity of supply. However, in good solar irradiance regions, there would be a point where higher solar PV to wind ratios would be more cost effective (along with the greater need for storage and transmission capacity) if wind generation costs became too expensive for too long.

To address the unique economic environment for wind, the recovery trajectory for both onshore and offshore wind has been modified to be 5 years slower than all other technologies. This has the effect of flattening out the projected cost trajectory in the next decade compared to the consultation draft.

Addition of large scale nuclear to the technology set

Technical limitations of large-scale nuclear

Advice provided to GenCost from its commencement in 2018 was that nuclear SMR technology is the most appropriate size for nuclear electricity generation in Australia. This statement is self-evident when measured against the size of individual generation units in Australia which are at most 750MW (at Kogan Creek) compared to large scale nuclear which starts at 1000MW and is commonly deployed at 1400MW for an individual unit. Some stakeholders in the most recent consultation pointed out that a coal generation site will have multiple units totalling more than 2000MW, but this is not relevant when considering the size of individual units.

Despite Australia's inexperience in individual generation units larger than 750MW, given the strength of feedback on this topic, the question of whether a larger generation unit could be accommodated in Australia was re-assessed. It was concluded that:

- A greater than 1000MW unit will require the deployment of more generation units in reserve than the existing system consisting of units of 750MW or less.

- By the time large scale nuclear could commence operation in 15-20 years' time[4] (a timeframe which considers the wide range of social, political, regulatory and technical factors), most large coal will be retired and as such may not be available to support planned and unplanned nuclear outages.
- In the absence of coal capacity, new capacity to address the unit reserve gap might be in the form of low emission dispatchable capacity such as storage and gas peakers given emission constraints that are likely to apply at the time[5].

There are existing arrangements to manage the issue of reserve adequacy. Should a large-scale nuclear project seek connection to the grid, the impact of planned and unplanned outages of large-scale nuclear on the electricity system would be assessed in the Electricity Statement of Opportunities (ESOO) process like it is for any other plant in the system. If the analysis showed system reserves were insufficient to manage outages to the relevant reliability standard, then the Reliability Obligation (RO) would be triggered for retailers to contract more investment in dispatchable capacity. In addition to the RO mechanism, high spot prices during times of large-scale nuclear outages would also go part way to encourage investment in technologies such as storage and gas after such events.

The new large-scale nuclear plant would need to submit information about how often planned outages will occur (through normal Projected Assessment of System Adequacy (PASA) arrangements). Unplanned outage assumptions would presumably have to be based on overseas data until Australia had more experience in operating the technology here. The analysis might also have to consider fuel supply chain risks, particularly if the fuel is imported (Australia does not currently refine uranium into fuel ready for input into electricity generation and such capability will not necessarily be developed in parallel with the initial deployment of nuclear generation). Enerdata (2024) recently highlighted some risks associated with future nuclear fuel supply including the dominance of Russia in global supply.

None of this analysis has been conducted for Australia's electricity systems which makes it difficult to reach a definitive conclusion. Overall, it is concluded that there are no known technical reasons why large-scale nuclear could not be accommodated in Australia. Additional investigation, focussed on the 2040s generation mix, would be required to rule out any barriers.

Large-scale nuclear cost data quality

GenCost's first preference is to use historical Australian project experience to estimate current costs. That is not possible for nuclear. The second preference is for overseas projects for which data is available. The challenges in converting overseas data to Australian data include:

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[4] See the longer discussion of this topic of the timing of first deployment of nuclear generation in Section 2

[5] It is also likely that storage and gas peaking capacity will be built anyway to support the deployment of variable renewables. It is not clear whether large-scale nuclear could use this existing capacity. Variable renewables need this capacity to do both daily electricity demand balancing as a result of normal daily weather variability and also to address more infrequent periods of low renewable production (so-called renewable droughts). If a large-scale nuclear outage occurred at the same time as either one of these events that impact variable renewable generation, then using existing capacity of dispatchable generation that is supporting renewables might not be sufficient to support new large-scale nuclear generation.

- Higher local installation costs compared to overseas best practice which is a phenomenon observed across most generation technologies in Australia (but not yet observable for nuclear until it is built in Australia)
- Lack of local workforce experienced in installing nuclear. This could mean that Australia experiences first-of-a-kind costs despite nuclear being a globally mature technology. An experienced workforce could be imported but that might entail extra costs, particularly if other countries are seeking to expand their own nuclear programs
- Available historical overseas data may not have accounted for the recent global inflationary cycle which has inflated the costs of all technologies relative to their pre-pandemic levels.

In the nuclear literature, lower cost installations in some regions of the world have variously been explained by:

- Low labour costs (e.g. recent UAE installations)
- The advantages of retaining a skilled workforce by maintaining an extended building program (e.g. South Korea's steady rate of nuclear plant additions)
- Lower environmental and safety standards
- Other contextual issues such as culture, governance and lower levels of litigation
- Explicit or obscured subsidies

In considering these topics Ingersoll et al. (2020) wrote the following when considering how the UK could try to achieve lower cost nuclear generation

"*Long-term, politically-supported fleet programmes, in Japan, Korea, and China have demonstrated repeatable low costs...Some of these cost reductions were also experienced in the UK, US, France, and Sweden during the height of new build programmes in the 1960s through 1980s. Such low cost nuclear build programmes require long-term cooperation of all key stakeholders… It is important to note that China, Korea, and Japan also enjoy several "contextual" benefits, especially for in-country projects that may not be transferrable to projects in the UK. For example, they benefit from significantly less expensive and more productive labour (i.e. more hours on task). In those countries, the regulator is paid by the government instead of by the reactor vendor or project developer. In addition, the regulator, while being sufficiently independent, is aligned with other project stakeholders on project completion. China benefits from the ability of state-run enterprises to quickly make large decisions once the political direction has been set – decisions that otherwise require a lengthy board approval process for private companies. All three countries benefit from cultures where litigious responses to problems are extremely rare for on-site issues…"*

Several stakeholders responding to the consultation draft suggested costs for large-scale nuclear in Australia but few provided evidence for how their proposed estimates addressed these widely known differences in nuclear technology deployment in the western world. To account for the issues discussed above, CSIRO developed a procedure to estimate capital costs for an Australian installed large-scale nuclear plant.

The approach is outlined in Section 2 where we detail the current capital costs of both SMR and large-scale nuclear costs. Some further discussion on the capital cost range used in the LCOE calculations is presented in Section 5.

Updates to the variable renewable LCOE calculations

Spilled electricity costs

There were two updates to the LCOE calculations for variable renewables. The first change relates to how the different cost components are combined. To support transparency, the methodology for incorporating integration costs for variable renewables has been to start with the existing non-integrated LCOE of variable renewables (which is published as the 'standalone' cost) and stack the additional integration costs on top of that. The non-integrated variable renewable cost at each 10% increase in variable renewable share (60% to 90%) is an optimised combination of the standalone solar PV and wind LCOEs but does not significantly vary with the variable renewable share under this method.

Some stakeholders wanted to understand why the cost of the underlying energy in the cost stack for variable renewables was not increasing as the VRE share increased. Typically, as variable renewable electricity generation increases, there is more unused electricity (i.e. that cannot be used by storage or direct demand). This results in a lower capacity factor for the useful electricity generated from variable renewables, increasing costs. As a result of the method used to combine costs, the LCOE did not previously call out this additional cost related to spilled electricity.

To address this issue, spilled electricity has been added as an additional explicit integration cost and features in revised charts in Section 5. The spilled electricity cost is calculated as the LCOE of the variable renewable generation equipment when calculated via total additional generation minus the LCOE when calculated on the basis of useful generation only (defined as the minimum additional generation needed to meet the next 10% increment of VRE share). The results indicate that spilled electricity is not a large factor overall in the integration costs, but its inclusion does make the results more comprehensive and intuitive.

Aligning costs with the worst case weather year and least cost combination of supporting technologies

The second change to the LCOE relates to how the elements of the integration costs are combined. The approach of previous GenCost results has been to take the highest cost result of nine weather years for each individual integration cost component. This meant that the higher cost transmission result might come from a different weather year than the highest cost storage result, for example. The principle that motivated this approach is that the electricity system, for any desired VRE share, should be designed to provide reliable electricity in the worst weather year.

However, on reflection, in achieving the required reliability outcome, the system will trade-off alternative least cost integration strategies. Storage, transmission and spilled electricity are all substitutes for one another such that an increase in reliance on one strategy reduces the need for the others. Another more specific interaction between these strategies is that some types of storage reduce the total requirement for synchronous condensers or system security capacity. The integration strategy the previous method was selecting was therefore not least cost.

In considering this, the methodology for selecting the highest integration costs was changed. The method now selects the highest cost weather year and takes all integration costs (spilled electricity, storage, transmission and system security costs) from that highest cost year. This means that the integration costs are internally consistent with each other, representing a least cost trade-off which is a key goal of the calculation method.

1.3.2 Minor changes

Changes to UAMPS nuclear SMR overnight capital costs

Two minor changes were made to the UAMPS (Utah Associated Municipal Power Systems) nuclear SMR overnight capital costs to better align with the basis for capital costs of other technologies (provided by Aurecon, 2024).

Overnight capital costs are the costs of deploying the technology as if it could be built overnight and before any payments to debt or equity for the financing of that construction. In practice it can take several years for projects to be built and any LCOE calculation needs to include a way of converting the overnight capital cost so that it accounts for the financing of development and construction costs during a period without any incoming revenue (see FAQ D.3.6).

The topic of financing costs potentially being included in the UAMPS nuclear SMR was raised by stakeholders. One interpretation was that all of the interest expenses during the life of the project (either incurred as debt or as the opportunity cost to any equity) were included in the total project cost when all other technologies only have their overnight capital costs included. Data that includes all these lifetime interest costs is very rare as few projects would willingly publicise their financing arrangements as they would reveal too much about targeted profit margins. Another interpretation is that financing costs only includes the cost of credit during the development and construction stages.

The most detailed description of the financing arrangements for the UAMPS nuclear SMR project that GenCost is aware of is published at https://www.utah.gov/pmn/files/936595.pdf. The information starts on page 167, ending on page 227. The concern about the inclusion of financing costs arises because in a "*Talking points*" document (starting from page 220) there is a statement that says "*Total cost of acquisition and construction, including financing: $9.3 billion*". Based on this statement the key question is what financing they are referring to. In investigating this issue GenCost reviewed a more detailed budget provided by UAMPS that also included significant detail on their plans for financing the project if it went ahead (see from page 200). This includes discussion of financing required to fund the pre-development stage.

It is reasonably clear from reviewing the more detailed budget available that the costs of the UAMPS project does not include lifetime interest. Interest expenses included are only related to that incurred during the pre-construction stage (also called development costs). The next stage of financing accumulates these costs into a single cost of development and construction. Note that pre-construction costs are a normal part of capital cost data that GenCost includes but not the interest incurred on this expense (see FAQ D.2.5 for a discussion on how this is included in technology capital costs). To eliminate any interest costs incurred on development costs from the overnight cost of capital, GenCost has removed US$1,588/kW from the nuclear SMR capital cost previously published in the consultation draft.

Stakeholders also indicated that the UAMPS CFPP budget includes transmission cost upgrades. GenCost found a reference to the inclusion of transmission upgrades in the UAMPS documentation. Unfortunately, no detail is provided in the budget on the nature of the upgrades or its share of project costs. However, the same phrasing was used in a presentation to the Idaho

Governor's LINE commission[6] where it is apparent in that document that the upgrade is referring to transmission interconnection costs. Aurecon (2024) states that it includes the cost of the step up transformer in the capital cost estimates that it provides. However, connection costs are not included in Aurecon capital costs. AEMO publishes connection costs for similarly sized combined cycle gas turbine generation units of $A100/kW on average. To be consistent with Aurecon's approach for other technologies, an additional $A100/kW has been subtracted from the nuclear SMR capital cost previously published in the consultation draft.

Re-inclusion of solar thermal generation in LCOE results

The LCOE of solar thermal generation was last included in GenCost 2021-22 in the flexible low emission technology category. It was removed in 2022-23 due to concerns that it was not being fairly represented relative to the other technologies in that category or consistent with the planned deployment of solar thermal in Australia. Other technologies in that category are assumed to operate with a capacity factor of 53% to 89% based on historical data. The capacity factor applied to solar thermal in 2021-22 was 42% to 52% based on some older planned project configurations.

Over time, plans for solar thermal deployment in Australia have been moving towards hybrid systems with solar PV generation during the day married with solar thermal for nighttime generation, drawing on its integrated storage capability. In this context GenCost 2022-23 had sought to place greater emphasis on the storage properties of solar thermal generation, including its capital cost alongside other storage technologies such as pumped hydro. This was not a perfectly fair comparison either given other storage technologies do not have the cost of their input energy embedded in their capital cost. A common basis for comparing storage technologies is possible through levelised cost of storage calculations, but this is presently out of scope for GenCost[7].

GenCost sought assistance from the Australian Solar Thermal Research Institute (ASTRI) to determine whether there was a fairer basis upon which solar thermal could be compared to other flexible low emission generation technologies. One option would be to develop a range of hybrid solar thermal electricity systems and their most relevant alternatives. However, at this stage, introducing several hybrid technologies into GenCost is out of scope. However, this might be possible for future report. For now, focussing purely on solar thermal generation, ASTRI commissioned ITP Thermal (2024) to explore whether it would be appropriate to operate solar thermal in the capacity factor range of 53% to 89% or, if not, what plausible range would solar thermal projects operate in. This built on the work by Fichtner Engineering (2023) who examined solar thermal in the Australian market, including very detailed cost modelling.

The context for this 53% to 89% range in GenCost is to explore the plausible maximum and minimum LCOE of flexible plant (based on observed historical operating conditions). For fuel based generation capacity such as coal, gas and nuclear, this approach makes sense because costs are

[6] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fline.idaho.gov%2Fwp-content%2Fuploads%2F2017%2F04%2FUAMPSLINE-Commission-17Jan17-2.pptx&wdOrigin=BROWSELINK

[7] Levelised costs of storage have been separately published by CSIRO in a one-off report available here: https://www.csiro.au/en/work-with-us/services/consultancy-strategic-advice-services/csiro-futures/energy-and-resources/renewable-energy-storage-roadmap

higher at lower capacity factors and lower at higher capacity factors. However, for solar thermal generation the maximum and minimum LCOE is largely driven by the quality of the solar resource at different locations in the electricity system. Capacity factor for solar thermal is more of an outcome of configuring the plant for the solar resource rather than a market operational decision after construction.

ITP Thermal (2024) found that while it would be possible to present solar thermal LCOE calculations that meet the criteria of a 53% to 89% capacity factor range it would likely be inconsistent with real project deployment. ITP Thermal (2024) studied two locations in the National Electricity Market (NEM) Wagga Wagga (in New South Wales) and Longreach (in Queensland) as plausible maximum and minimum cost locations respectively. At each site they studied the least cost configuration and found that the capacity factor for the least cost configuration in the high cost site (Wagga Wagga) was 57%, avoiding $11/MWh in costs compared to 53%. In the low cost site (Longreach) the capacity factor for the least cost configuration was 71%, avoiding $47/MWh in costs compared to 89%.

Based on these findings, solar thermal has been re-included in the flexible low emission technology group for the LCOE results. However, given the importance of configuring the plant capacity factor to the solar resource available, we allow the solar thermal maximum and minimum cost range to be based on the narrower 57% to 71% capacity factor range. Widening the range purely to match the other technologies in the category would be inconsistent with project design and only increase the cost at both the maximum and minimum ends of the range for solar thermal generation which does not add to our understanding of the plausible range.

Additional minor changes

Other brief changes are:

- Provided more clarity on the data sources used in the LCOE calculations and a table of costs included in the 2023 LCOE calculation
- Added the Kurri Kurri gas plant in the 2023 LCOE for variable renewables with integration costs given its delayed operation to end of 2024. The Tallawarra B plant is in operation and so is not included as a new cost.
- Expanded the description of nuclear development times to more clearly articulate why the development pipeline for nuclear is different to other technologies. This includes a revision of nuclear construction times.
- Included a discussion of first-of-a-kind costs and which technologies they are relevant to.
- Nuclear fuel costs were revised to take into account current higher prices
- Data sourced from Wilson (2021) and Heard (2022) references for nuclear SMR costs were expanded to include a range instead of a mid-point. Additional Energy Information Administration (2023) data was also added.
- The coal plus 5% risk premium category was removed from the LCOE analysis. Unabated fossil fuel generation still faces unique financing risks but the 5% factor is based on older research which likely no longer captures the true depth of asset stranding risk now faced by fossil fuels. Also, removal of this category allows more room to include additional categories to the charts such as large-scale nuclear and solar thermal.

- The representative black coal plant type has changed from supercritical to ultra-supercritical

1.3.3 Topics to be considered for future releases of GenCost

The topics to be considered for future reports are listed here. They have not been immediately implemented because they were not considered feasible to include in this report and are still being evaluated. However, general considerations are time and budget constraints, data availability and prioritisation based on their value in meeting the purpose of GenCost.

- Requested technology additions to GenCost include gas infrastructure (for renewable methane and hydrogen) such as pipelines and storage, flat plate solar PV as a lower cost version of single-axis tracking large-scale solar PV, ammonia storage, hydrogen storage in pressure vessels, thermal storage for heat and more customer-level technology options.
- In addition to the above point, Aurecon considered the cost of vanadium redox flow batteries in its 2021-22 report. At that stage it did not appear to be a viable candidate to compete against conventional lithium batteries. Given the greater experience and deployment of this technology since that time, it will be useful to re-examine in a future capital cost update.
- Capital cost projections to be disaggregated by installation costs (which are driven by local learning) and equipment costs which are driven by global learning. Readers should note that the Excel file of current costs provided by Aurecon (2024) provides a breakdown of equipment, installation and combined development and land costs.
- Explicit workforce modelling to determine the impact of labour market forces on Australian development and installation costs over time.
- An analysis of the historical forecasting accuracy of GenCost. In considering when to implement such a review, it is acknowledged that GenCost did not forecast the pandemic and subsequent global supply chain constraints and inflationary impacts. Very few forecasting projects are designed to account for such 'black swan' events given that, although they can be predicted as a possibility in the future, their specific timing is impossible to predict. Due to the pandemic and its subsequent impacts, any review implemented now would find capital costs were significantly higher than projected, particularly in 2022 and 2023. No major in-depth data analysis is required to reach this conclusion. However, a review in around two years from now could be valuable in determining how well the methodology for projecting cost behaviour in the aftermath of the pandemic has performed.
- Review the feasibility of providing a simplified open source electricity model for exploring integration costs for variable renewables and other new-build technologies. The need to model transmission costs and the connection of new renewable energy zones makes most electricity system models too large and complex for an individual to support on their own without the backing of an organisation to cover the costs of quality linear program solver licences and the high effort required to populate such models with the required data. However, submissions to the consultation process indicated there are individuals who are interested in this topic and would like a model to test different generation mixes to better understand variable renewable integration challenges. Several submissions were from individuals with their own unpublished models. Others cited models that are available in academic literature and as a result are often more transparent with model equations and some data inputs provided. The range of results

from these academic models is currently divergent[8]. This reflects a combination of different model constraints, input data and researchers asking the models to answer slightly different questions. If excluding transmission costs can be considered a necessary trade-off for greater transparency, a common modelling framework for exploring variable renewable integration costs might be possible.

- Add levelised cost of storage as a metric that is regularly provided in GenCost. CSIRO (2023) provided this data but it has historically been out of scope for GenCost.

[8] More detail on the likely reasons for this divergence are discussed in the LCOE section of Appendix D.

2 Current technology costs

2.1 Current cost definition

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

While all data is useful in its own context, our approach reflects the objective that the data must be suitable for input into electricity models. The way most electricity models work is that investment costs are incurred either before (depending on construction time assumptions) or in the same year as a project is available to be counted as a new addition to installed capacity[9]. 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 Aurecon (2024). Aurecon (2024) also provide more detail on specific definitions of the scope of cost categories included. Aurecon 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. Aurecon 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.

Aurecon (2024) also provides detailed information on the boundary of capital costs such as what development costs are included, ambient temperature, distance to fuel source, water availability 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

[9] 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 by the process of more detailed engineering and feasibility studies prior to final investment decisions but may not be shared publicly.

Therefore, we can only warn stakeholders that some projects will cost significantly more than projected in Section 4. EIA (2023) apply FOAK premiums of up to 25% to their technology costs. AACE (1991) recommend 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. As such, while special circumstances occurred in each case, we cannot rule out FOAK premiums of 100% applying to other projects in the future.

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

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

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 last deployment leading to loss of skills, new designs which create uncertainty or new licensing requirements, and unique site conditions.

It is likely that 2023 nuclear SMR costs include some FOAK costs. The extent of that FOAK component will not be completely transparent until further projects proceed. The first commercial project did not proceed, and the next may be some years ahead. Further complicating matters, the first commercial project to almost proceed coincided with a large global inflationary event. We can remove all the identifiable inflationary impacts based on a costing that was available before the pandemic, but cannot reliably identify the FOAK share of the cost increase. However, if part of the increase between 2020 and 2022 was due to FOAK, it is removed over time in the projection method that is applied in Section 4.

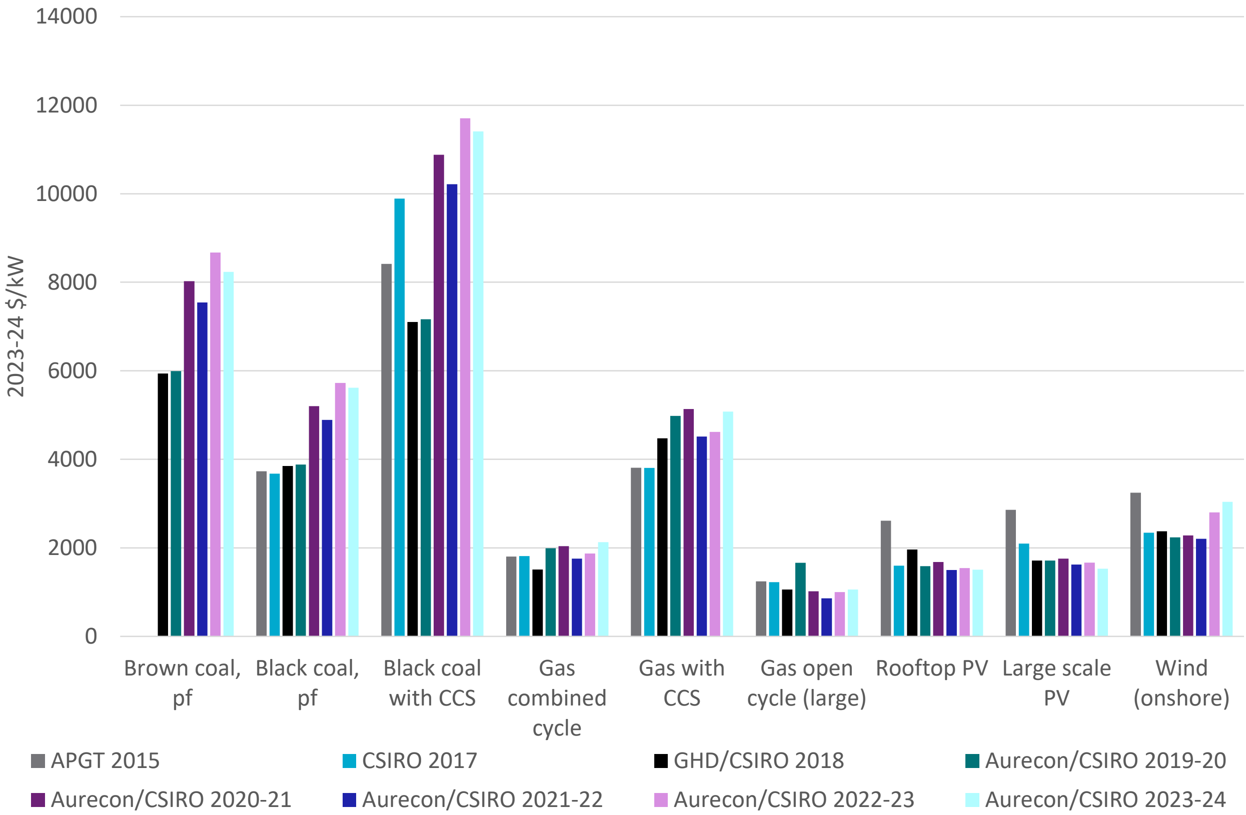
2.2 Capital cost source

AEMO commissioned Aurecon (2024) to provide an update of current cost and performance data for existing and selected new electricity generation, storage and hydrogen production technologies. We have used data supplied by Aurecon (2024) which is consistent with either the beginning of financial year 2023-24 or middle of 2023. Aurecon provides several measures of project capacity (e.g., rated, seasonal). We use the net capacity at 25ºC to determine $/kW costs. Aurecon state that the uncertainty range of their data is +/- 30%.

Technologies not included in Aurecon (2024) are typically those which are not being deployed in Australia but are otherwise of interest for modelling or policy purposes. For these other technologies we have applied an inflationary factor to last year's estimate based on a bundle of consumer price indices applied to knowledge of the relative mix of imported and local content for each technology. Pumped hydro has been updated by Aurecon (2024) whereas previously this was sourced from AEMO. Where cost estimates are based on technologies not deployed recently and recent inflationary factors are not therefore observable, GenCost has added a cost factor which is then removed over time.

2.3 Current generation technology capital costs

Figure 2-1 provides a comparison of current (2023-24) cost estimates (drawing primarily on the Aurecon (2024) update) for electricity generation technologies with those from previous years: GenCost 2018 to GenCost 2022-23 (which are a combination of Aurecon (2021, 2022, 2023), GHD and CSIRO data), Hayward and Graham (2017) (also CSIRO) and CO2CRC (2015) which we refer to as APGT (short for Australian Power Generation Technology report).



Black coal pf changes from supercritical to ultra-supercritical in 2023-24
Figure 2-1 Comparison of current capital cost estimates with previous reports

All costs are expressed in real 2023-24 Australian dollars and represent overnight costs. Rooftop solar PV costs are before subsidies from the Small-scale Renewable Energy Scheme.

Whilst there had been some steady declines over the years for technologies such as solar PV and wind, for 2022-23, there was a universal increase in capital costs (20% on average). In 2023-24, the result was more mixed with solar PV reducing in costs while gas and onshore wind technology costs have been increasing (Figure 2-2). The source of the 2022-23 increase was 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 are also recovering from this development at different rates. However, overall, it can be said that the impacts are less in 2023-24 than the previous year.

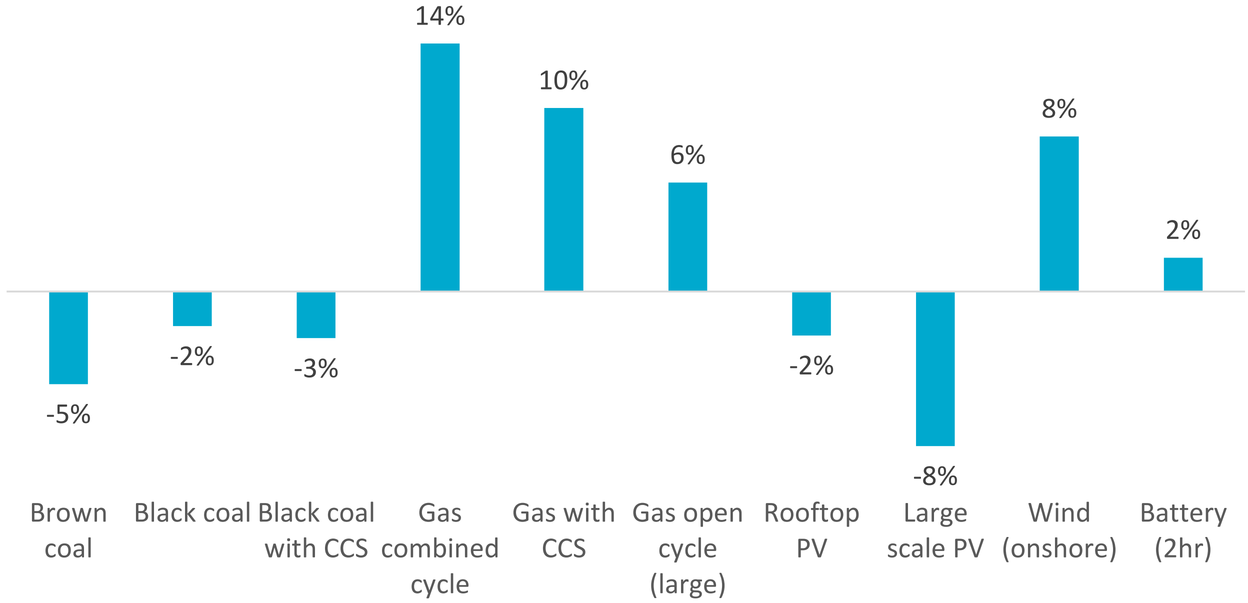


Figure 2-2 Change in current capital costs of selected technologies relative to GenCost 2022-23 (in real terms)

2.4 Update on current cost of nuclear SMR

2.4.1 Challenges in determining capital costs of nuclear SMR

An ongoing issue for the estimation of the capital costs for nuclear SMR has been the lack of data from completed commercial projects. Completed commercial projects or signed contracts for completion are the preferred data source for all capital cost estimates in GenCost. While there are completed projects in Russia and China these were 100% government funded rather than commercial projects which makes it difficult to ascertain what their costs would be in a market setting.

CSIRO has been monitoring the broader literature to try to firm up the current costs of nuclear SMR in the absence of our preferred data source. Such literature has tended to represent theoretical projects. More recently costs have become available for real projects, however, not at the stage yet of signed contracts for completion (consequently, costs for such projects could still change up to that point).

2.4.2 Early estimates for theoretical projects

Early estimates for theoretical projects have tended to be presented as a range representing the high degree of uncertainty in emerging technologies. In its *2015 Projected Cost of Generating Electricity*, the IEA (2015) stated that FOAK nuclear SMR project costs were expected to be 50% to 100% higher than the current cost of large scale nuclear. Based on large-scale nuclear costs in that report, this results in a range of $12,500/kW to $16,700/kW (all data in this report from all sources is adjusted to Australian dollars and inflated to 2023-24 dollars unless otherwise stated[10]). In 2018 the Canadian SMR Roadmap provided a list of f FOAK project costs collected from the literature (EFWG, 2018). The range was wider still, from $8,200/kW to $19,100/kW.

In 2019 the US Energy Information Administration published its *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (EIA, 2019). It claimed that a theoretical FOAK nuclear SMR project could be constructed for $10,300/kW. This appeared to align with the lower end of the range of previous literature. Their next update in 2023 was for $12,766/kW.

Two in-depth Australian publications that provided costs for nuclear SMR in Australia are Wilson (2021) and Heard (2022). They estimated capital costs of between $3,460/kW to $7,980/kW. Both studies relied on theoretical costs provided by technology vendors which were a mix of FOAK and NOAK data for 2020.

GenCost reports which begin from 2018 (Figure 1), chose to adopt the high end of the range of costs from these theoretical cost estimates, particularly relying on the Canadian SMR Roadmap. The reason for using the high end of the range was because most estimates were for countries that already had nuclear electricity generation and it was assumed that, because Australia has no experience in nuclear electricity generation, it would be more likely to experience higher costs. Another consideration was that historically vendors are over-optimistic about their own technologies before they have practical experience in deploying it commercially.

2.4.3 Recent estimates from a leading US project[11]

UAMPS (Utah Associated Municipal Power Systems) is a US regional coalition that develops local government owned electricity generation projects. Up until the project's cancellation in November 2023, it was the developer of a nuclear SMR project called the Carbon Free Power Project (CFPP) with a gross capacity of 462MW[12]. It was planned to be fully operational by 2030. After conversion to 2023 Australian dollars, project costs were estimated in 2020 to be $18,200/kW (DOE, 2023)

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[10] An exchange rate of 0.7 US dollars per Australian dollar was applied. Prices were adjusted to today's dollars using the Australian Bureau of Statistics Consumer Price Index.

Note that IEA (2015) was the original source for information provided to GenCost by GHD in 2018. However, they recommended a cost of $19,000/kW (adjusted for today's prices) which later aligned well with the high end of the Canadian SMR Roadmap data.

[11] Another SMR project we are monitoring is the Darlington project in Canada. However, they had not made their costs public at the time of publishing. Their costs are for a brownfield project at an existing nuclear generation site and so will need to be adjusted to be on a greenfield basis once the data becomes available. https://www.opg.com/projects-services/projects/nuclear/smr/darlington-smr/

[12] https://www.uamps.com/Carbon-Free

which is only slightly below the level that GenCost had been applying ($19,000kW). This validated GenCost's use of the higher cost range in the theoretical data available at the time.

In late 2022 UAMPS updated their capital cost to $28,580/kW citing the global inflationary pressures that have increased the cost of all electricity generation technologies (UAMPS, 2023). GenCost 2022-23 found that most technology capital costs had increased in 2022 by 20%, up to a maximum of 35% for onshore wind. Accordingly, we had increased our own cost estimate of nuclear SMR by 20% to $22,470/kW. However, the UAMPS estimate implies nuclear SMR has been hit by a much larger 57% cost increase. Consequently, GenCost 2023-24 current capital costs for nuclear SMR have been modified to bring them into line with this more recent estimate. The cancellation of this project is significant because it was the only SMR project in the US that had received design certification from the Nuclear Regulatory Commission which is an essential step before construction can commence. It is also the only recent estimate from a real project that was preparing to raise finance for the construction stage. As such, its costs are considered more reliable than theoretical projects.

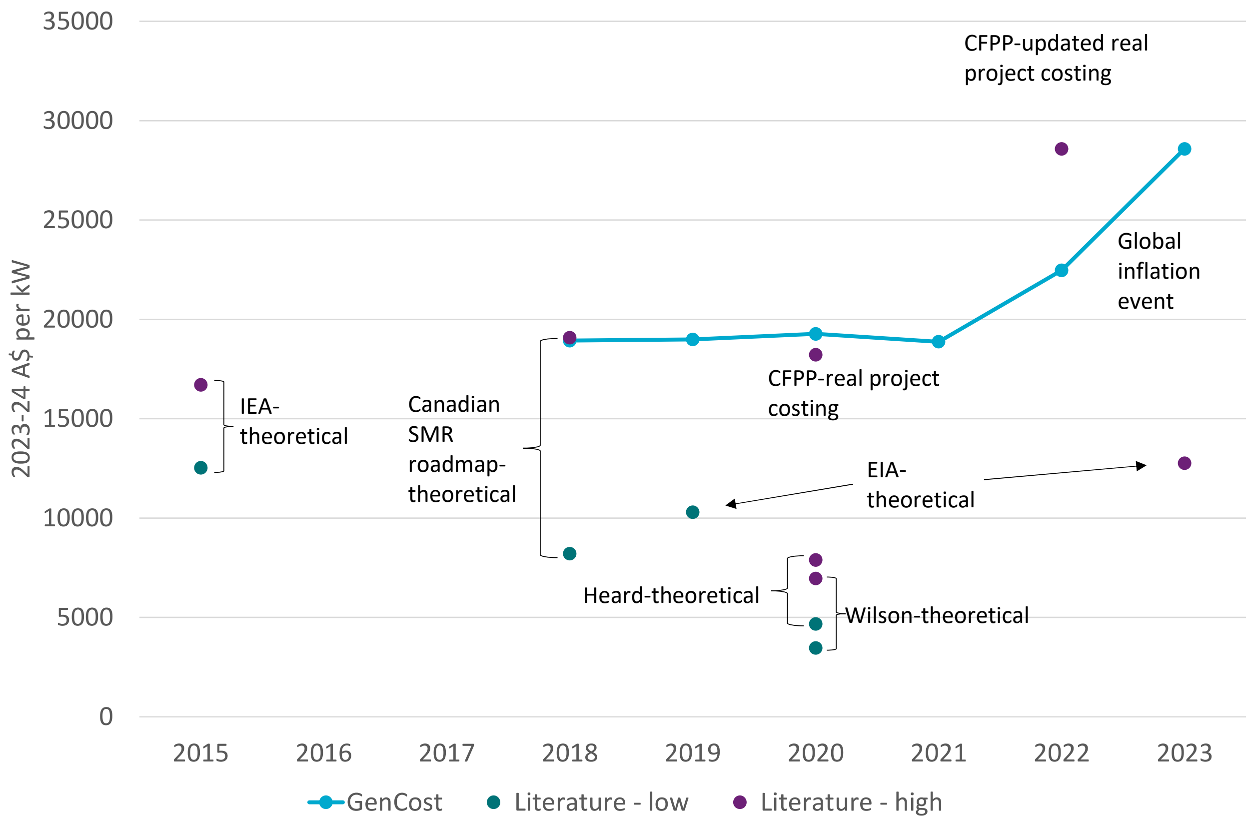


Figure 2-3 Timeline of nuclear SMR cost estimates (calendar year) and current costs included in each GenCost report (financial year beginning)

2.5 Estimating large-scale nuclear costs

Large-scale nuclear plant costs as defined in media releases are generally not detailed enough for use in comparison with other data. For any data source the cost basis needs to be clearly understood because costs may be announced with or without factors such as contingency and owners' costs which can make a significant difference. We have therefore confined our sources to those that have sufficient clarity on their cost basis.

Our approach is to include a large-scale nuclear cost that represents the cost associated with a continuous building program. Costs from new or sporadic national building programs are at risk of incurring FOAK premiums. While we recognise the likely occurrence of a FOAK premium, where possible, GenCost does not include them for other technologies not yet deployed in Australia[13] and so does not intend to do so for large-scale nuclear. South Korea was identified as the best representation of a continuous building program.

South Korea has been building nuclear power stations on an almost continuous basis since the 1970s. They recently completed the Shin-Hanul Unit 1 in December 2022 and Unit 2 was completed in January 2024. They used their own technology, APR 1400 for these projects and aim to continue to build this technology into the 2030's.

South Korea's nuclear plant costs can therefore be considered as an example of NOAK costs, which Australia may achieve if between 5 to 10 units are built on a continuous basis (US DOE 2023).

The primary source for South Korean new-build large scale nuclear costs was IEA (2020). This source requires modification to make the data relevant as input to Australian large-scale new-build nuclear costs. To convert overseas large-scale nuclear plant costs to Australian costs, GenCost has examined the differences in ultra-supercritical (USC) coal plant costs, comparing Australian costs to South Korean USC coal costs and observing the ratio of nuclear costs and USC costs in the same country.

The reason USC coal plant costs were used to develop large-scale nuclear plant costs for Australia is that both USC coal and nuclear plant have large nameplate capacities, use conventional steam turbines and associated equipment, require significant construction labour input and have long construction times compared to other types of power plants.

The IEA (2020) included both USC and APR 1400 nuclear plant overnight costs each as a single value. However, the IEA (2020) overnight costs include contingency (15% for nuclear and 5% for other technologies) and owners costs which are not included in Aurecon (2024) or GHD (2018) costs. GHD (2018) costs were used as the basis for the Australian USC costs as costs from 2018 and 2020 were not subject to inflationary pressures as the Aurecon (2024) costs are. Therefore, these sets of costs are more comparable. Owners' costs for both USC and nuclear are 7% and 25% respectively (EIA 2024). Therefore, in the absence of other data, these percentages were subtracted from the South Korea USC and APR 1400 nuclear costs. New-build coal fired power stations in South Korea include pollution controls, therefore Australian-based pollution control costs (CO2CRC 2015) were added onto the GHD (2018) USC costs. The USC costs for South Korea were calculated for a much larger plant capacity than GHD (2018): 954 MW compared to 724 MW. The South Korean USC costs were thus scaled using the power law relationship of 0.6, which is typical for large scale plant (Peters et al., 2003). These calculations have resulted in USC and nuclear costs for South Korea on the same EPC cost basis as GHD (2018) and Aurecon (2024).

[13] GenCost has not identified a consistent method for calculating a FOAK premium across all relevant technologies ahead of observing the first deployment. Furthermore, a FOAK premium should only be applied to the first deployment and therefore requires a forecast of deployment which is outside the scope of GenCost. We do discuss the earliest possible deployment time for some technologies but that does not mean they will be deployed at that time.

These costs are:

- South Korea USC: $1,142/kW (USD 2018)
- South Korea APR 1400 nuclear: $1,746/kW (USD 2018)

The ratio of Australian to South Korean USC costs is 2.8 when all costs are in the same currency units. Therefore, the South Korean nuclear costs were scaled up by 2.8 and inflated and converted from USD 2018/kW to AUD 2023/kW. The resultant cost is $8,655/kW (AUD 2023). This cost includes some current global inflationary impacts which are removed over time consistent with the approach taken for other technologies.

As discussed, the capital cost for the first large-scale nuclear project will be higher than this capital cost estimate as it will be for all FOAK in Australian technologies. This capital cost is only achievable for a steady, continuous building program.

2.6 Perceived inconsistency between high nuclear capital costs and 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 and this was pointed out by several stakeholders. 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. Other differences include unknown or known subsidies and different levels of state versus private ownership.

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.

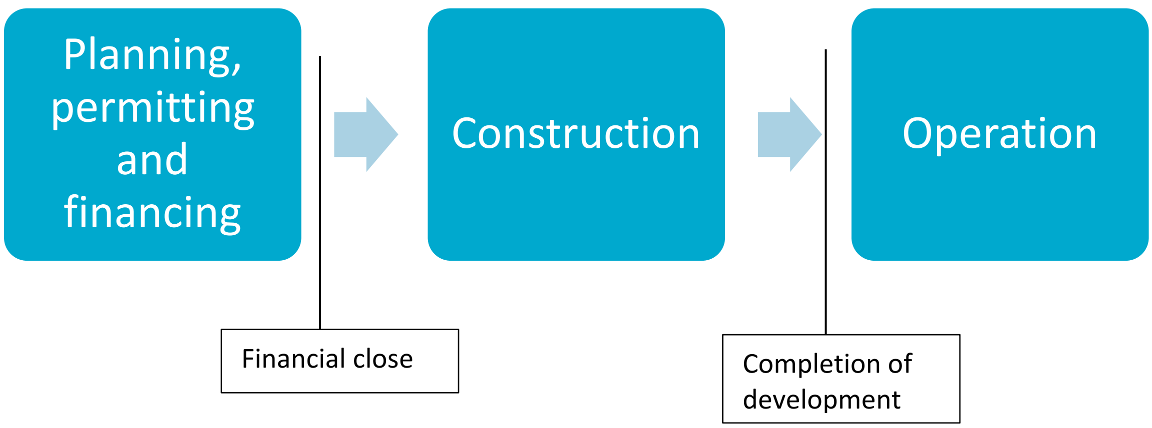
In summary, given overseas new generation electricity costs are not easily transferable and may be referring to assets that are not seeking to recover costs equivalent to a commercial new-build nuclear plant, there may be no meaningful comparison that can be made between overseas nuclear electricity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

2.7 Timing of deployment of nuclear in Australia

Commencing from the GenCost 2020-21 report, nuclear SMR capital costs were only reported from 2030. This was due to advice from stakeholders that nuclear SMR costs before 2030 were irrelevant for Australia because before that date there is no prospect of an Australian project (allowing 10 years from the time of that discussion). This date had not been revised for several years and is out of date.

Since the release of the consultation draft of GenCost 2023-24 the whole timeline of nuclear costs has been included in the report and, instead of the previous 2030 date as a guide, this extended discussion about timing is included. Submissions received and public discussion on the question of the timing of nuclear in response to the consultation draft has been mixed. The discussion has sometimes lacked clarity on the distinction between the concepts of total development time and construction time. Total development time includes construction but also a range of pre-construction activities. These pre-construction activities[14] include, for example, site selection and acquisition, technology design and engineering, grid connection and impact studies, permitting of the technology, environmental permits, sourcing fuel and water and any associated permits if relevant, accessing project financing including power purchase agreements, accessing project development and construction teams or contractors. When these steps are complete a project is said to have reached financial close and can begin construction. Construction ends when the project is fully operational (Figure 2-4).

Both the GenCost and Aurecon reports emphasise construction time because capital costs are fixed at the point of financial close. However, at any point in time, there are a large number of projects that are working through the pre-construction development stage. The mix of projects at different stages of development before construction is often called the 'development pipeline'. In Australia, due to long standing renewable energy targets at the national and state level, most projects in the development pipeline are for technologies which meet or support those targets: solar PV, wind, storage and gas projects. AEMO tracks and publishes the development pipeline for the NEM[15]. As at April 2024, there were 11GW committed, 9GW anticipated and 280GW proposed. This is relative to an existing 65GW of generation capacity.



[14] The pre-construction portion of total development time is also known as the lead-time.

[15] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

Figure 2-4 New generation project stages

Prior to the pandemic, Clapin and Longden (2024) report that solar and onshore wind projects had an average pre-construction time of 41 and 53 months respectively. This decreased from an average of 83 and 136 months prior to 2010. Anecdotally, pre-construction times have increased again after the pandemic owing to competition for resources and labour that has been impacted by constricted global supply chains.

Despite some slowing down of the number of projects coming to financial close after the pandemic, the existence of such a deep development pipeline means that many renewable or renewable supporting projects are reaching financial close every year. This fortunate situation is not shared by nuclear. Nuclear power has no projects in the development pipeline in Australia. This is not surprising given the existing legal prohibitions at the state and commonwealth level. Therefore, although it is true that all technologies have extensive pre-construction development times, nuclear is unique in that is has an empty development pipeline in Australia. It is also important to recognise that nuclear has several additional steps in its pre-construction timeline that other technologies do not have. Nuclear technologies need to undergo more extensive safety and security permitting, nuclear prohibitions need to be removed at the state and commonwealth level and the safety authorities need to be established.

Given the lack of a development pipeline and the additional legal and safety and security steps required, the first nuclear plant in Australia will be significantly delayed. Subsequent nuclear plant could be built more quickly as part of a pipeline of plants. Establishing a pipeline may be more difficult for large-scale nuclear than SMRs. Existing plant may not be able to retire quickly enough to accommodate a steady pipeline of large scale nuclear. The pace at which a fleet of large-scale nuclear plant could be deployed will depend on the age of the existing generation capacity at the time their deployment is being considered.

After the pre-construction phase, construction time for nuclear SMR is assumed to be 4.4 years based on the stated construction period of the CFPP project[16]. Construction time for large-scale nuclear is assumed to be 5.8 years based on Lazard (2023).

A 2023 senate committee for the Environment and Other Legislation Amendment (Removing Nuclear Energy Prohibitions) Bill 2022 heard evidence about nuclear SMR development completion times. The view from regulators was that it would be around 15 years to first production from a decision to build nuclear SMR in Australia, emphasising the time taken to revise regulations[17]. Even though legislation in the US is more developed, it is interesting to note that, had the CFPP proceeded in the US, it would have taken 15 years from its formal launch[18] to complete full operation in 2030 as planned. If 15 years is reasonable for SMR, given the longer construction time of large-scale nuclear plant, their total development time would be a few years longer. A 15+ year total development time would mean that if a decision to pursue nuclear in

[16] See page 200 of https://www.utah.gov/pmn/files/936595.pdf Although this project did not proceed it remains the only data source available that relates to a recent real SMR project. All other data is for theoretical projects at lesser stages of project development or from pilot projects in countries too different from Australia.

[17] https://www.aph.gov.au/Parliamentary_Business/Hansard/Hansard_Display?bid=committees/commsen/26831/&sid=0009

[18] https://inl.gov/trending-topics/carbon-free-power-project/. This development timeline is also clear from page 200 of https://www.utah.gov/pmn/files/936595.pdf

Australia were made in 2025, with political support for the required legislative changes, then the first full operation would be no sooner than 2040.

In support of shorter total development timelines, some stakeholders sought to emphasise project development times in the UAE given they started from a similar point of having an empty nuclear development pipeline. Total development time for the first large-scale nuclear plant in the UAE was 13 years (spanning from 2008 with the release of their nuclear strategy[19] until 2021). However, stakeholders have also pointed out that the UAE is not a democracy and therefore may have abbreviated some stages of permitting that will take longer in Australia due to the greater degree of public consultation in many of its governance processes. Other information presented in support of shorter development times is that there is support provided from the nuclear industry for countries new to nuclear and that the structure and operation of safety and security permitting agencies can be adapted from overseas. Some stakeholders also noted that ANSTO developed a reactor for the production of medical supplies in around 10 years.

Given the potential for an extended development timeline, a risk for nuclear generation developers is political change. That is, they could commence the development process, incurring development expenses, but before reaching financial close they may find that a change in government results in a modification of the required permitting steps or prohibits nuclear altogether. Without bipartisan support, given the historical context of nuclear power in Australia, investors may have to consider the risk that development expenses become stranded by future governments. Of course, other technologies face some level of this risk as well, but to a much lesser degree given shorter total development times and a longer history of successful permitting.

2.8 Current storage technology capital costs

Updated and previous capital costs are provided on a total cost basis for various durations[20] of batteries, adiabatic compressed air energy storage (A-CAES) and pumped hydro energy storage (PHES) in $/kW and $/kWh. Battery durations of 24 hours and 48 hours have been added for the first time. 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), 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[21]. 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 2-5). The downward trend flattens somewhat with batteries since its power component,

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[19] https://www-pub.iaea.org/MTCD/publications/PDF/cnpp2016/countryprofiles/UnitedArabEmirates/UnitedArabEmirates.htm

[20] 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

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

mostly inverters, is relatively small but adding more batteries increases capital cost. However, the hydroelectric turbine in a PHES project is a large capital expense while adding more reservoir is less costly. As a result, PHES capital costs fall steeply with more storage duration.

Note that these $/kWh costs are not for energy delivered but rather a capacity of storage. GenCost does not present levelised costs of storage. However, these are available from the CSIRO (2023) *Renewable Energy Storage Roadmap*. While A-CAES appears relatively higher capital cost at present, it is mainly competing with pumped hydro for longer duration storage applications. PHES is not expected to improve in costs and may be more distant to some locations.

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 2-6). 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 depending on the operation of other generation in the system, particularly the scale of variable renewable generation and peaking plant (see Section 5).

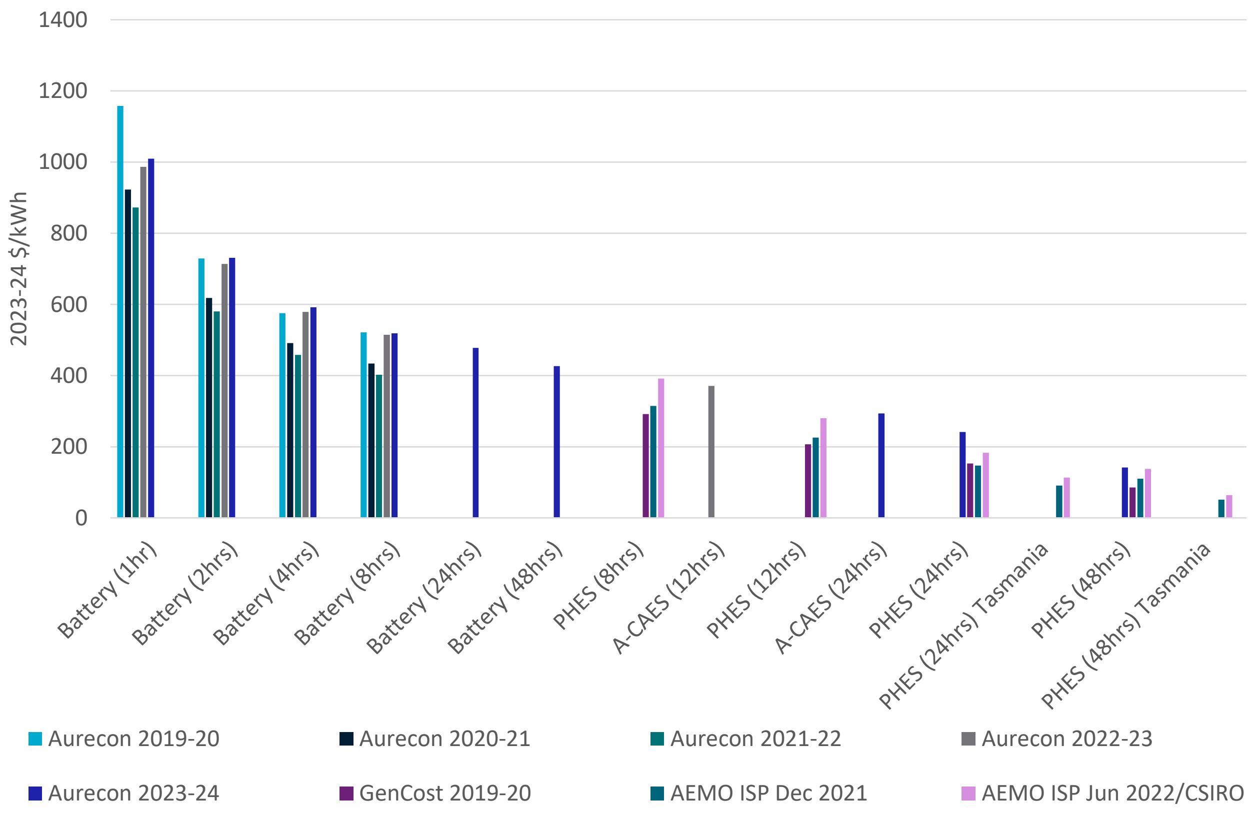

Figure 2-5 Capital costs of storage technologies in $/kWh (total cost basis)

Depth of discharge in batteries can be an important constraint on use. However, all Aurecon battery costs are presented on a usable capacity basis such that depth of discharge is 100%[22].

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[22] 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%.

Aurecon (2024) also includes estimates of battery costs when they are integrated within an existing power plant and can share some of the power conversion technology. This results in a 5% lower battery cost for a 1-hour duration battery, scaling down to a 1% cost reduction for 8 hours duration and negligible for longer durations. PHES is more difficult to co-locate.

The current capital costs of the storage technologies have increased in 2023-24. Battery costs (battery and balance of plant in total) have increased slightly by only 1-2% depending on the duration.

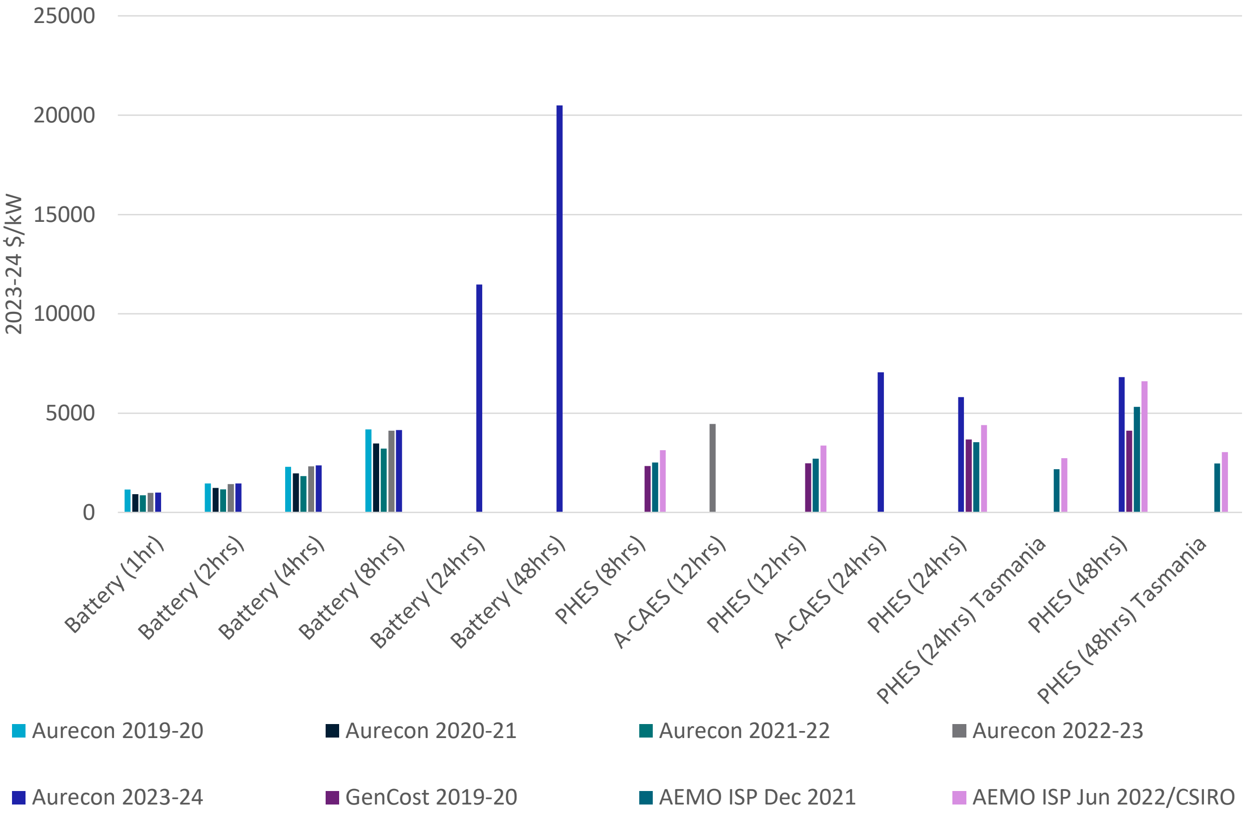

Figure 2-6 Capital costs of storage technologies in $/kW (total cost basis)

PHES current cost estimates have increased by 32% for 24 hour duration projects and by only 3% for 48 hour duration projects indicating the increase is more so in the power equipment and installation than the reservoir[23]. These increases cannot all be assigned to global inflationary pressures because this is the first new capital cost estimates for pumped hydro since the Entura (2018) study which has been the basis of previous AEMO data used in this report. The increase likely represents a fresh perspective informed by additional information since 2018 on pumped hydro projects.

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. As an indicator of the influence of site costs, we have included the cost of Tasmania pumped hydro for 24 and 48 hours duration. AEMO provides state and regional cost adjustment

[23] The PHES capital costs used in this report are based on taking the mid-point of the range provided by Aurecon (2024). Percentage differences will be higher or lower for projects at different ends of that range.

factors for PHES and other technologies as part of the *Inputs and Assumptions Workbook* publication.

A-CAES is not yet integrated into our projection methodology and so its future costs are not presented in this report. While some components are mature, its deployment is not widespread relative to other options. Aurecon (2024) has provided a 24 hour duration cavern storage A-CAES project cost. A cost for vessel storage is also provided by Aurecon for 12 hour duration but is not reported here given its high cost. It appears that cavern will be the preferred storage method where possible given the cost advantage.

Concentrating solar thermal is another technology incorporating storage but is no longer included in this section. Concentrating Solar Thermal (CST) is analysed as a flexible low emissions 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. This has been addressed via the comparison of Levelised Costs of Storage (LCOS) in CSIRO's Energy storage roadmap (CSIRO, 2023), but is outside the scope of GenCost.

3 Scenario narratives and data assumptions

The scenario narratives 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 2023 World Energy Outlook (IEA, 2023) 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.

3.1.1 Current policies

The *Current policies* scenario includes existing climate policies as at mid-2023 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[24]. . 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 strong climate policy consistent with maintaining temperature increases of 1.5 degrees of warming and achieving net zero emissions by 2050 worldwide. The achievement of these abatement outcomes is supported by the strongest

[24] 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.

technology learning rates and the least constrained (physically and socially) access to variable renewable energy resources. Balancing variable renewable electricity is less technically challenging. Reflecting the low emission intensity of the predominantly renewable electricity supply, there is an emphasis on high electrification across sectors such as transport, hydrogen-based industries and buildings leading to the highest electricity demand across the scenarios.

Table 3-1 Summary of scenarios and their key assumptions

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

1 The learning rate is the potential change in costs for each doubling of cumulative deployment, not the rate of change in costs over time. See Appendix 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

4.1 Short term inflationary pressures

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 those projected by learning-by-doing and economies of scale.

CSIRO has explored a number of resources to understand cost increases already embedded in technology costs and 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 four to seven years. It is not appropriate to project long term future costs directly from the top of a price bubble, otherwise all future costs will contain the current temporary market conditions.

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 either a cartel 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[25]). The 2023-24 update to current costs has mixed information with some technology costs declining, some flat and some increasing. However, as a group, it indicates inflationary pressures are weakening.

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, particularly for the *Global NZE by 2050* and *Global NZE post 2050* scenarios. 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

[25] 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.

use the turning of a decade as a target date for achieving energy targets. The *Current policies* scenario requires less growth in technology deployment and as such, for that scenario only, 2027 remains the date at which we assume costs resume their pre-pandemic modelled pathway.

In response to feedback, this report includes one exception which is that wind costs do not return to their normal path until 2035. Of all the technologies that are currently in high demand, wind capital costs were impacted the most and have demonstrated to be the slowest to recover. It is therefore appropriate to give onshore and offshore wind a separate pathway.

A consequence of this modelling approach is that all of the cost reductions to either 2027 or 2030 (or 2035 for wind) mostly do not reflect learning. Rather, they are predominantly the slow unwinding of inflationary pressures that have temporarily placed costs above the underlying learning curve.

The exception to the resumption of a modelled cost path after 2027, 2030 or 2035 is that the projection has been adjusted to recognise that land may be a source of ongoing input scarcity. 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 Aurecon (2024) and inflate that proportion of costs by the real land cost index that is published in Mott MacDonald (2023)[26]. 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 is a recent feature, first included in *GenCost 2022-23: Final report*.

All projections start from a current cost and the primary source of 2023 costs is Aurecon (2024) with data gathered from other sources where otherwise not available in that report.

While we have used the trends in price indices of selected goods to inform our analysis, all projections remain in real terms. That is, all projected cost changes after 2023 are in addition to the general level of inflation.

4.2 Global generation mix

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

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

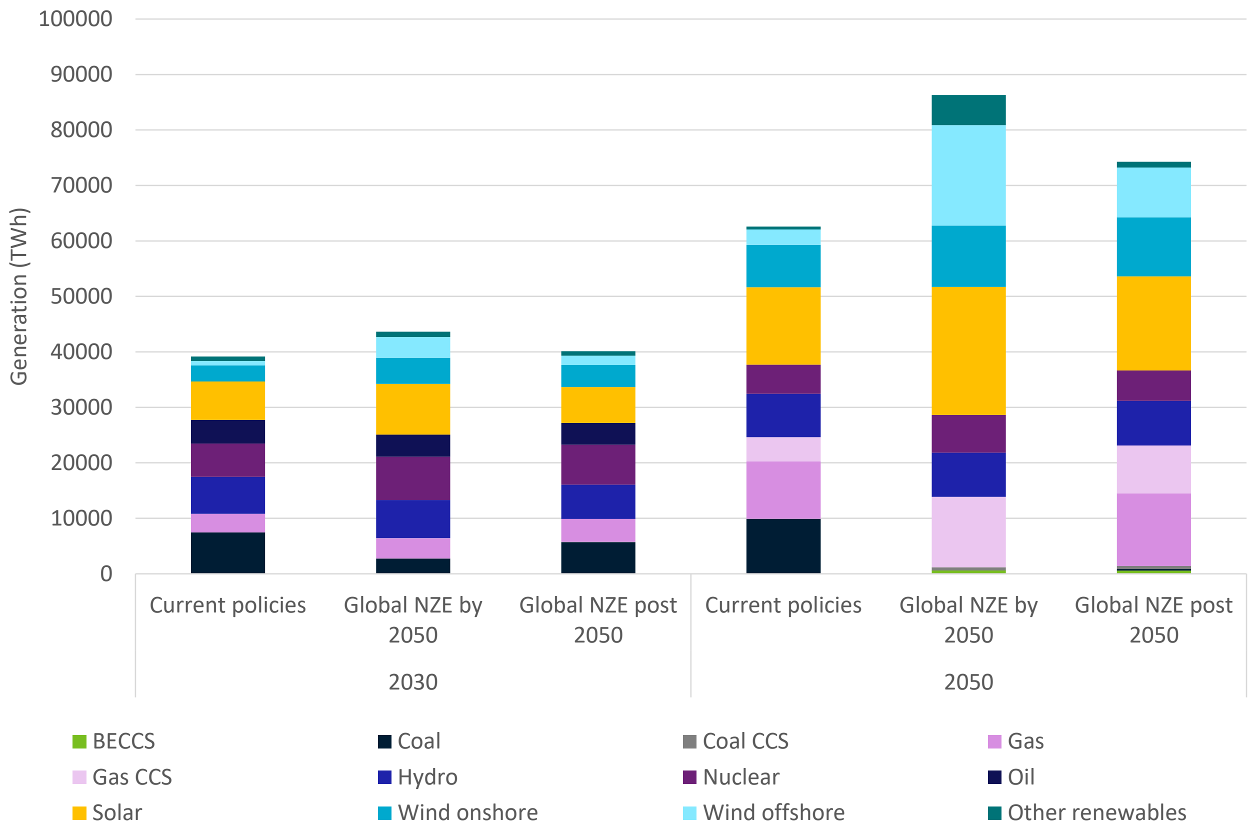

Figure 4-1 Projected global electricity generation mix in 2030 and 2050 by scenario
The technology categories displayed are more aggregated than in the model to improve clarity. Solar includes solar thermal and solar photovoltaics.

Current policies has the lowest electrification because it is a slower decarbonisation pathway than the other scenarios considered. However, it has the least energy efficiency and industry transformation[27]. 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.

Current policies has the lowest non-hydro renewable share at 40% 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 increases the higher the climate policy ambition of the scenario, but is around 8% in all scenarios by 2050.

The *Global NZE by 2050* scenario is close to but not completely zero emissions by 2050. 99% of generation from fossil fuel sources is with CCS accounting for 16% of generation by 2050. Offshore wind features strongly in this scenario at 21% of generation by 2050. Renewables other than

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

hydro, biomass, wind and solar are 6% of generation in 2050. The greater deployment of renewables and CCS leads to lower renewable and CCS costs.

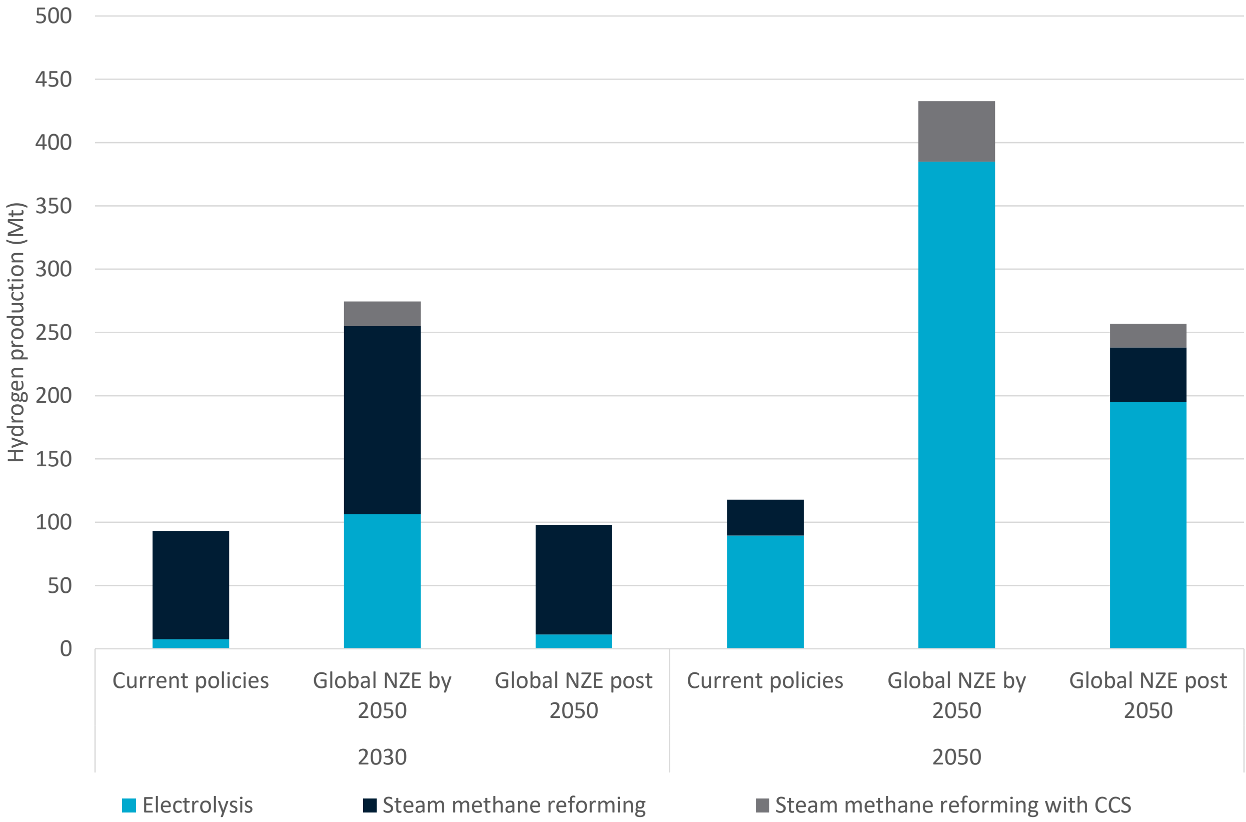

Figure 4-2 Global hydrogen production by technology and scenario, Mt

4.3 Changes in capital cost projections

This section discusses the changes in cost projections to 2050 compared to the 2022-23 projections. For mature technologies, where the current costs have not changed and the assumed improvement rate after 2027 or 2030 (depending on the scenario) is very similar, their projection pathways often overlap. The land cost inflator results in a 56% increase in land costs by 2050 but this is only a small portion of capital costs. Before the land cost inflation is added, the assumed annual rate of cost reduction for mature technologies post-2027 or 2030 (depending on the scenario) is 0.35% (the same as previous reports given the rate is based on a long-term historical trend). The method for calculating the reduction rate for mature technologies is outlined in Appendix A. Data tables for the full range of technology projections are provided in Appendix B and can be downloaded from CSIRO's Data Access Portal[28].

4.3.1 Black coal ultra-supercritical

The cost of black coal ultra-supercritical plant in 2023 has been included Aurecon (2024). The black coal capital cost had previously been based on older data on supercritical plant so we have taken

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

this opportunity to update the black coal technology to ultra-supercritical. From 2023 the capital cost is assumed to return to levels prior to the COVID-19 pandemic by 2027 in *Current policies* and by 2030 in the *Global NZE* scenarios, reflecting our approach for incorporating current inflationary pressures outlined at the beginning of this section. Black coal ultra-supercritical is treated in the projections as a learning technology. However, global new building of ultra-supercritical coal is limited to the *Current policies* scenario and the learning rate is low. The outlook for costs in all scenario is flat, with a slight increase due to increasing land costs.

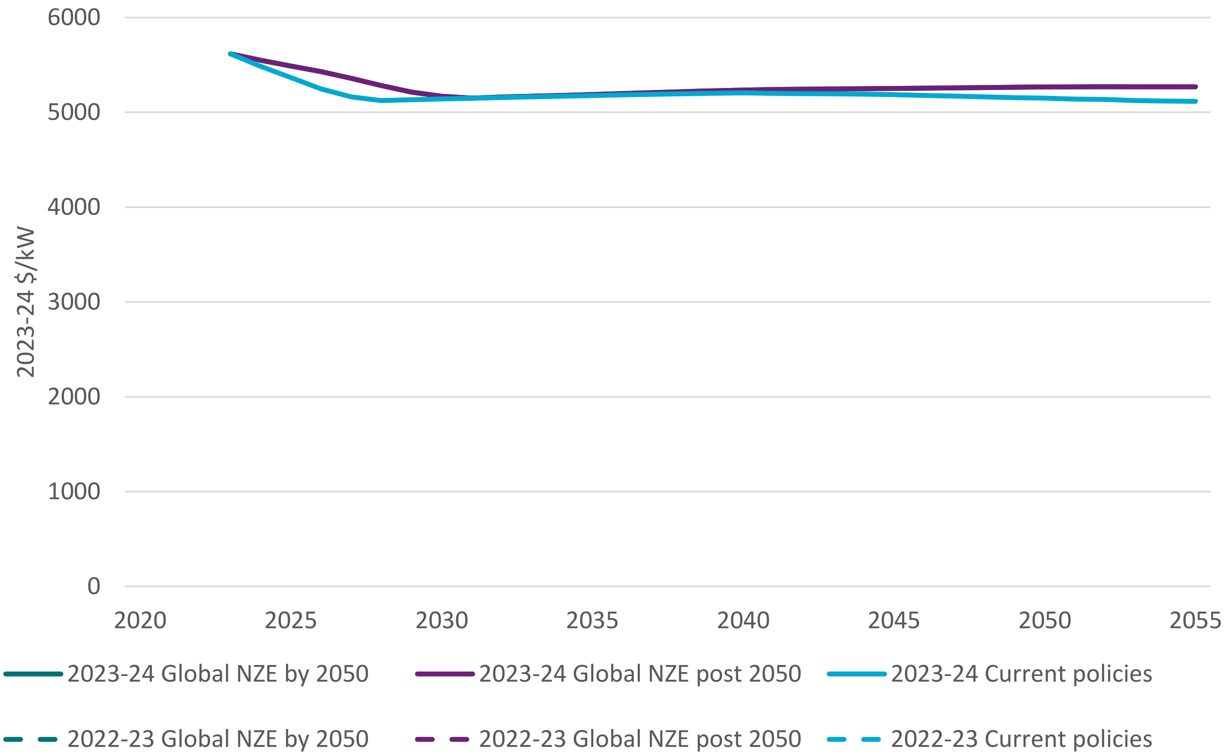

Figure 4-3 Projected capital costs for black coal ultra-supercritical by scenario

4.3.2 Coal with CCS

The current cost of black coal with CCS from 2023 to 2027 in *Current policies* or 2023 to 2030 in the *Global NZE* scenarios has been updated in a similar manner as mature technologies, but with differences to take account of its unique set of inputs. Thereafter, the capital cost of the mature parts of the plant improves at the mature technology cost improvement rate. For the CCS components, the cost reductions are a function of global deployment of gas and coal with CCS, steam methane reforming with CCS and other industry applications of CCS. Cost reductions up to 2027 or 2030 are not technology related but rather represent the weakening of current inflationary pressures.

Current policies has no uptake of steam methane reforming with CCS in hydrogen production. Consequently, cost reduction from the late 2030s are mainly driven by the deployment of 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.

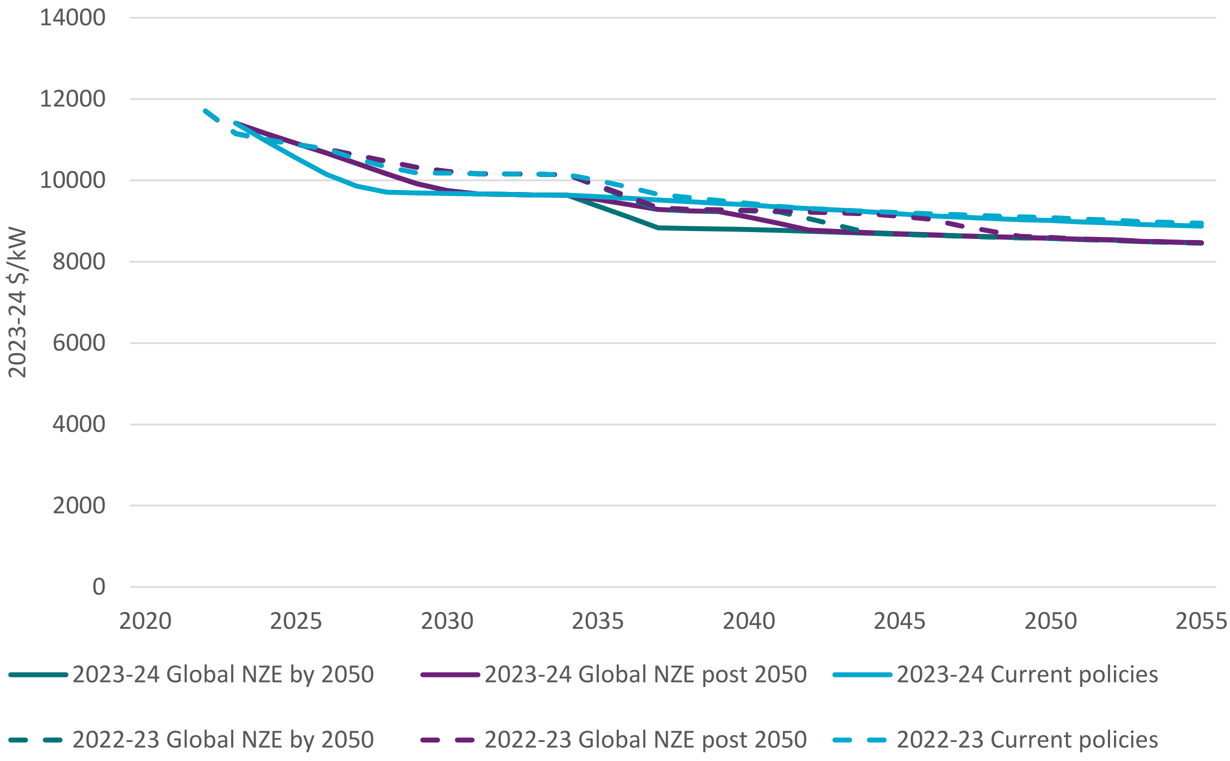

Figure 4-4 Projected capital costs for black coal with CCS by scenario compared to 2022-23 projections

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). Given the scale of generation and hydrogen production required in those scenarios, together with assumed high other industry use of CCS, the total deployment of CCS technologies across all applications is high. The total 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 learning and cost reduction by 2050 but with differences in the timing of reductions.

4.3.3 Gas combined cycle

Aurecon (2024) have included an increase in gas combined cycle costs for 2023 and CSIRO has imposed an assumed return to previous costs levels by 2027 in *Current policies* and 2030 in the *Global NZE* scenarios. 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 by our assumed cost improvement rate for mature technologies together with a land cost increase for all scenarios. Consequently, the rate of improvement is constant across the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios.

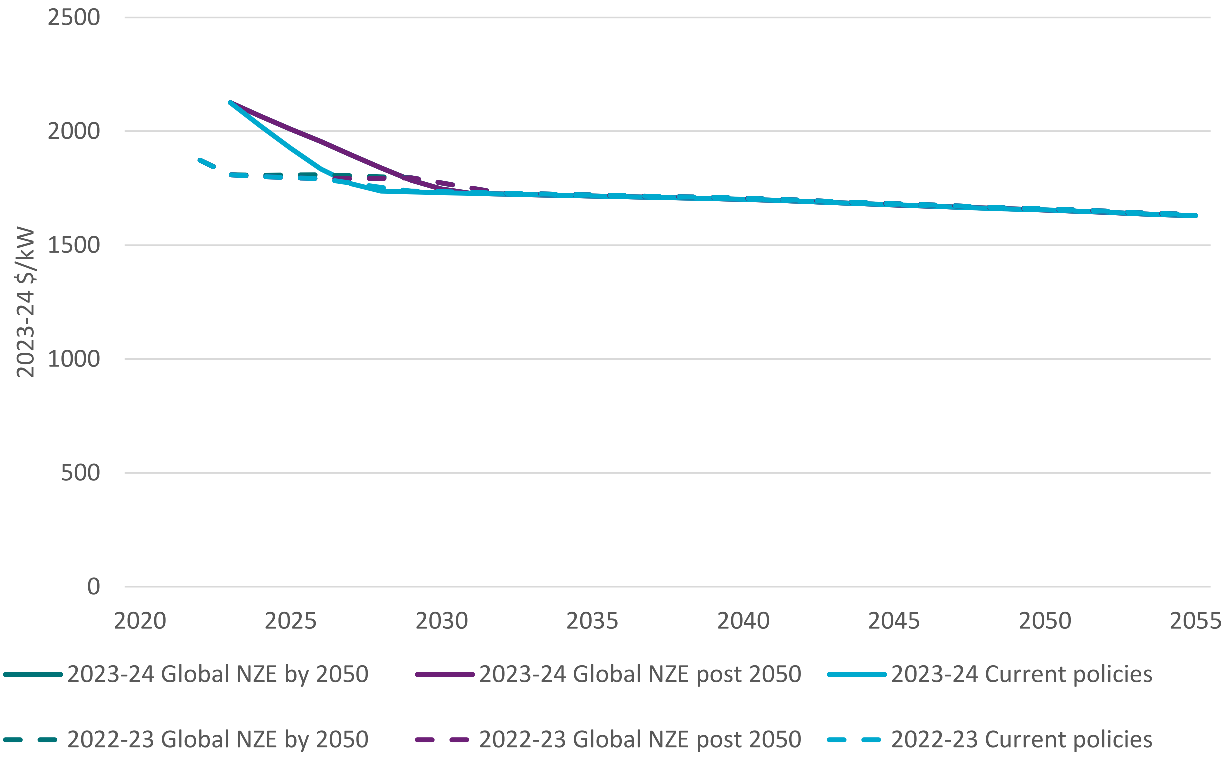

Figure 4-5 Projected capital costs for gas combined cycle by scenario compared to 2022-23 projections

4.3.4 Gas with CCS

The current cost for gas with CCS has been revised upwards for the 2023-24 projections reflecting the increase in gas combined cycle capital costs. The relativities between the scenarios reflect the differences in global deployment in electricity generation, hydrogen production and other industry uses of CCS. *Global NZE by 2050* and *Global NZE post 2050* have the highest total deployment of all CCS technologies. Subsequently gas with CCS is lowest by 2050 in those scenarios. Conversely, CCS is highest cost in *Current policies* where CCS deployment is lowest.

The IEA CCS database[29] indicates there are around 30 planned electricity related projects which are yet to make a financial investment decision, two under construction and one completed. The advanced projects are for smaller volumes and/or low capture rates. Given the current state of the pipeline of projects, significant global deployment of CCS is not expected until after 2030.

[29] CCUS Projects Database - Data product - IEA

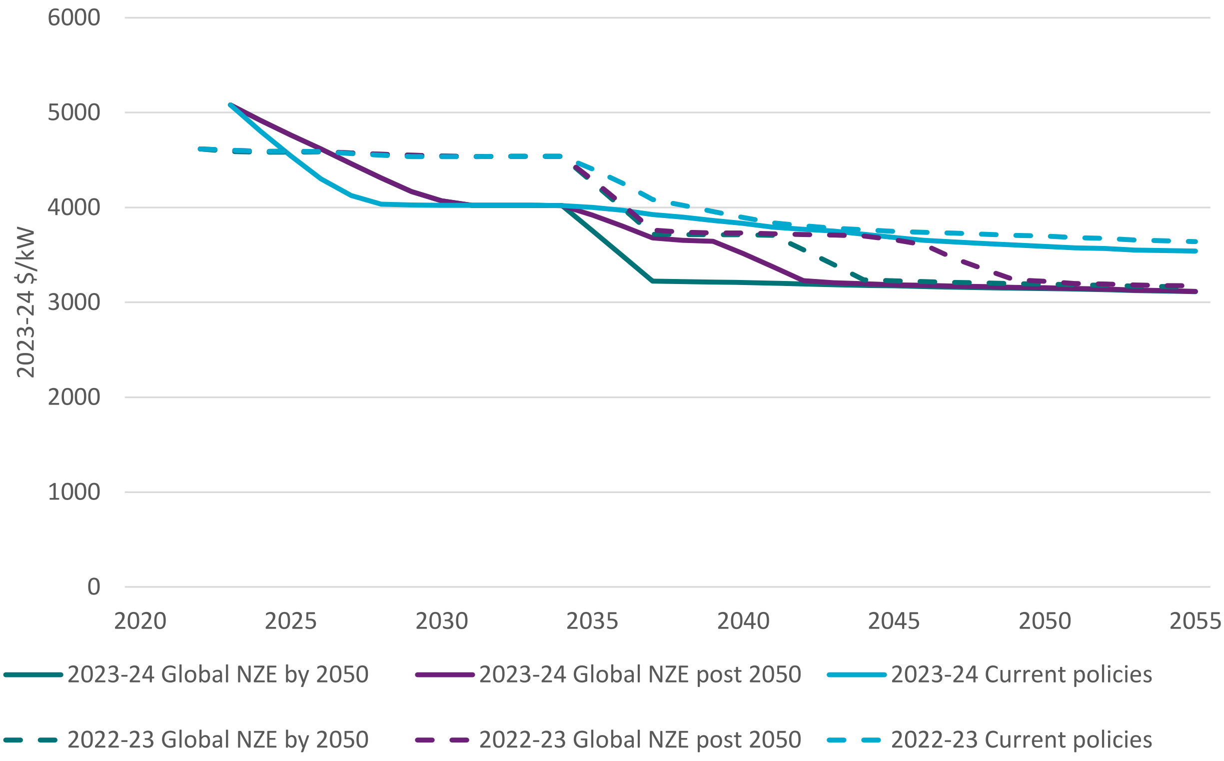

Figure 4-6 Projected capital costs for gas with CCS by scenario compared to 2022-23 projections

4.3.5 Gas open cycle (small and large)

Figure 4-7 shows the 2022-23 and updated 2023-24 cost projections for small and large open cycle gas turbines. Aurecon (2024) provides the details for the unit sizes and total plant capacity that defines the small and large sizes. Current costs are higher for both sizes based on the updated 2023 data. However, a further cost increase was anticipated for 2023 in the previous projections and aligns well with the updated cost. Capital costs are assumed to converge towards their previous projected levels by 2027 or 2030. Aside from assumed increasing land costs, open cycle gas is classed as a mature technology for projection purposes and as a result its change in capital costs is also governed by our assumed cost improvement rate for mature technologies. Consequently, the rate of improvement is constant across the scenarios.

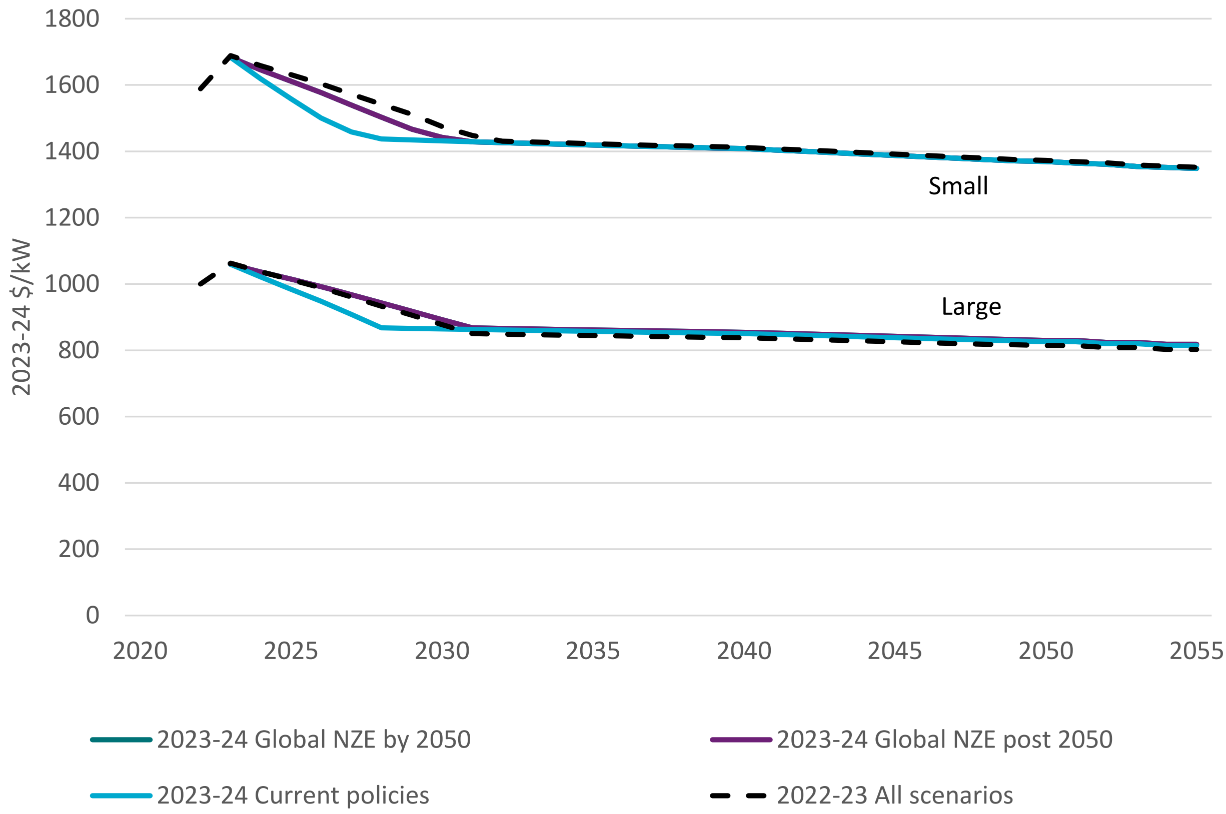

Figure 4-7 Projected capital costs for gas open cycle (small) by scenario compared to 2022-23 projections

4.3.6 Nuclear SMR

Given the lack of global commercial deployment and very low expectation of deployment in Australia, GenCost previously did not report cost data before 2030 for nuclear SMR. However, as discussed in Section 2.4, more information has become available on the current cost of nuclear SMR, and it is now reported from 2023.

New information has meant that the scenarios are less divergent than previous projections but higher on average. The projections start at the updated 2023 capital cost of around $28,600/kW. Like all other technologies, we assume costs converge back to a level that does not include the current short term inflationary impacts. The new published information discussed in Section 2.4 has been useful in determining the pre-inflationary cost level. There is also some learning within the period to 2030 assuming projects at advanced planning stages proceed. Beyond 2030, further deployment of less developed projects needs to proceed to achieve further cost reductions. Capital costs only improve slightly for the *Current policies* scenario due to a low deployment of projects in the 2030s followed by a later stage of deployment in the 2050s.

In the *Global NZE* scenarios, the scale of abatement and growth in demand means that existing commercial technologies are not sufficient to achieve global electricity sector emissions reduction. As a result, significant deployment of nuclear SMR proceeds in some regions with subsequent cost reductions achieved during the 2030s through the learning rate assumptions which may be partly driven by modular manufacturing processes. Modular plants reduce the number of unique inputs that need to be manufactured. There is some variation in the timing and depth of cost changes with *Global NZE post 2050* around $2500/kW lower on average. Capital costs are between approximately $11,000/kW and $15,000/kW across the scenarios.

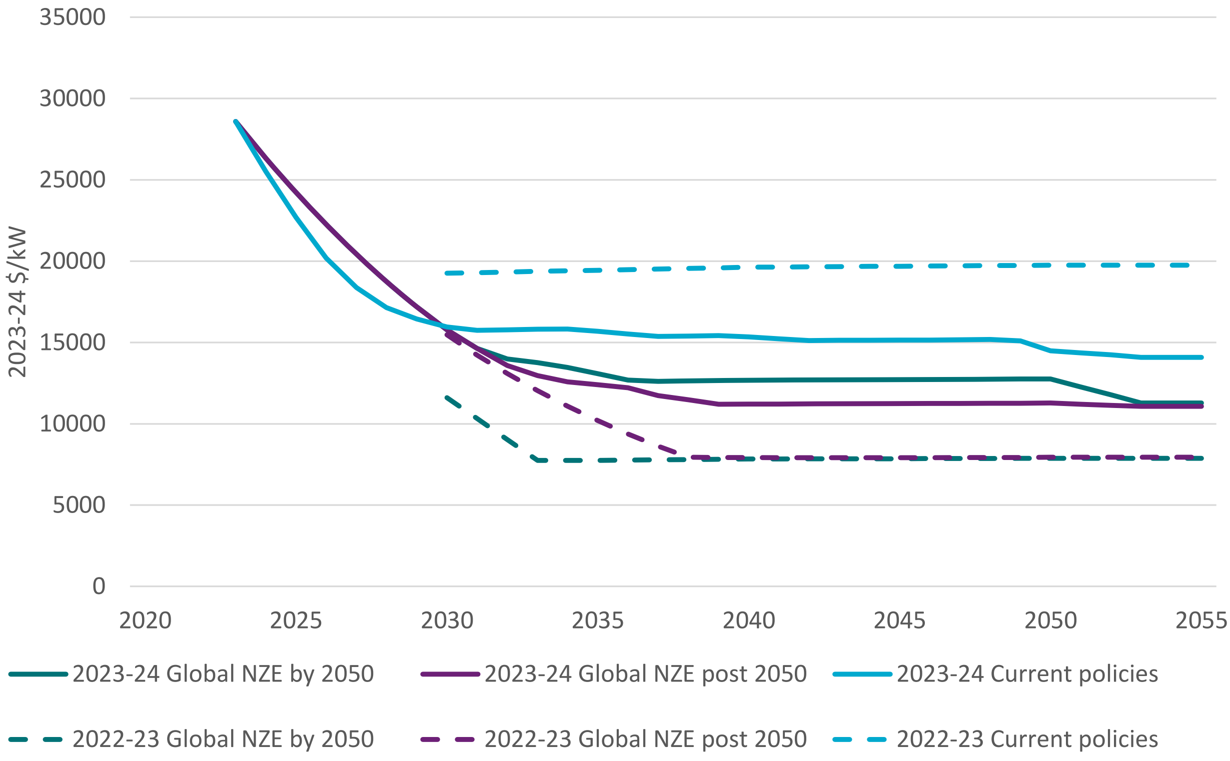

Figure 4-8 Projected capital costs for nuclear SMR by scenario compared to 2022-23 projections

4.3.7 Large-scale nuclear

Large-scale nuclear has been introduced into this GenCost report and so there are no 2022-23 projections to compare current projections to. Discussion of how the current cost of large-scale nuclear was determined was discussed in Section 2.5. Like other technologies, large-scale nuclear capital costs are assumed to return their underlying costs, before the current global inflationary cycle, by 2027 in *Current Policies* and by 2030 in the *Global NZE* scenarios.

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 decline after 2027 or 2030 at the pre-determined annual cost reduction rate assigned to all mature 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 in assigning 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 around proven designs.

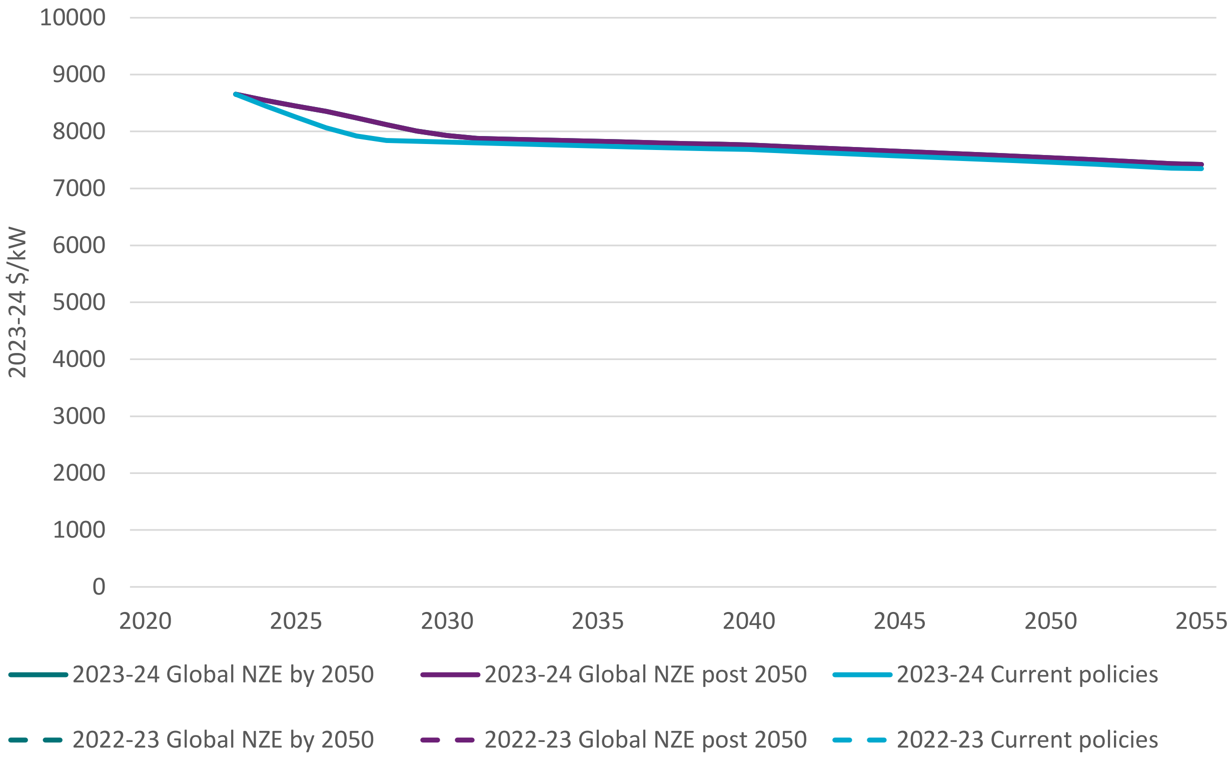

Figure 4-9 Projected capital costs for large-scale nuclear by scenario

4.3.8 Solar thermal

The starting cost for solar thermal has been updated by Aurecon (2024) drawing on Fichtner Engineering (2023) which includes a change to the baseline configuration, reducing storage duration from 15 hour to 14 hours and an adjustment for inflationary pressures in 2022. Due to lack of projects, it is unknown whether solar thermal would have been subject to further cost inflation in 2023. This factor, together with the change in configuration mean that the apparent cost reduction compared to the previous year's data should be viewed with caution. This current year cost reduction is the main cause for changes in the projection compared to 2022-23. Otherwise, the projections diverge by a similar amount according to their scenario with the greatest cost reductions projected to be stronger the greater the global climate policy ambition.

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.

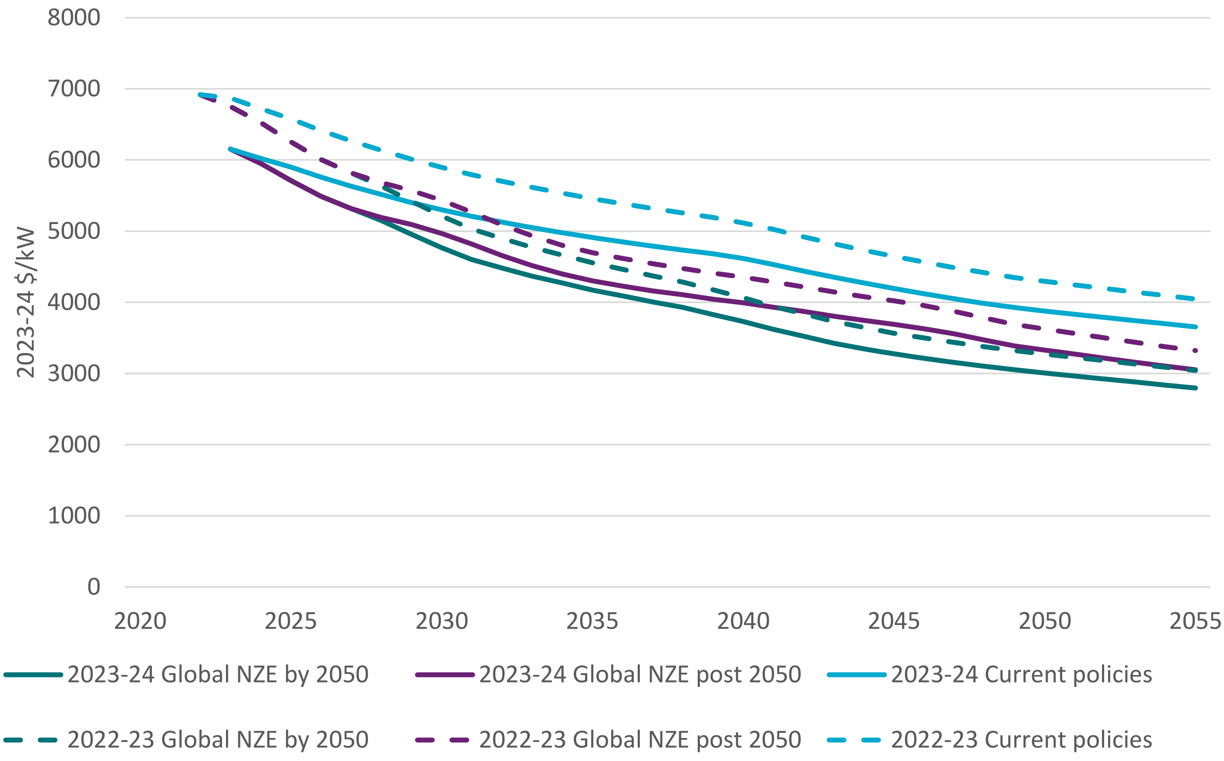

Figure 4-10 Projected capital costs for solar thermal with 14 hours storage compared to 2022-23 projections (which was based on 15 hours storage)

4.3.9 Large scale solar PV

Large-scale solar PV costs have been revised downwards for 2023-24 based on Aurecon (2024) indicating solar PV production costs are recovering more rapidly than projected from global inflationary pressures. Under the *Current policies* scenario, costs fully return to their normal cost pathway by 2027. In the *Global NZE* scenarios, inflationary pressures remain higher for longer due to faster technology deployment to meet stronger climate policies, but between 2030 and 2040 experience a similar level of uptake and subsequent cost reductions.

By 2055, deployment has converged leading to different cost outcomes the three scenarios project a capital cost range of $570/kW to $780/kW. The final minimum cost level for solar PV is one of the most difficult to predict because, unlike other technologies, and notwithstanding current extreme inflationary pressures, the historical learning rate for solar PV has not slowed. The modular nature of solar PV appears to be the main point of difference in explaining this characteristic.

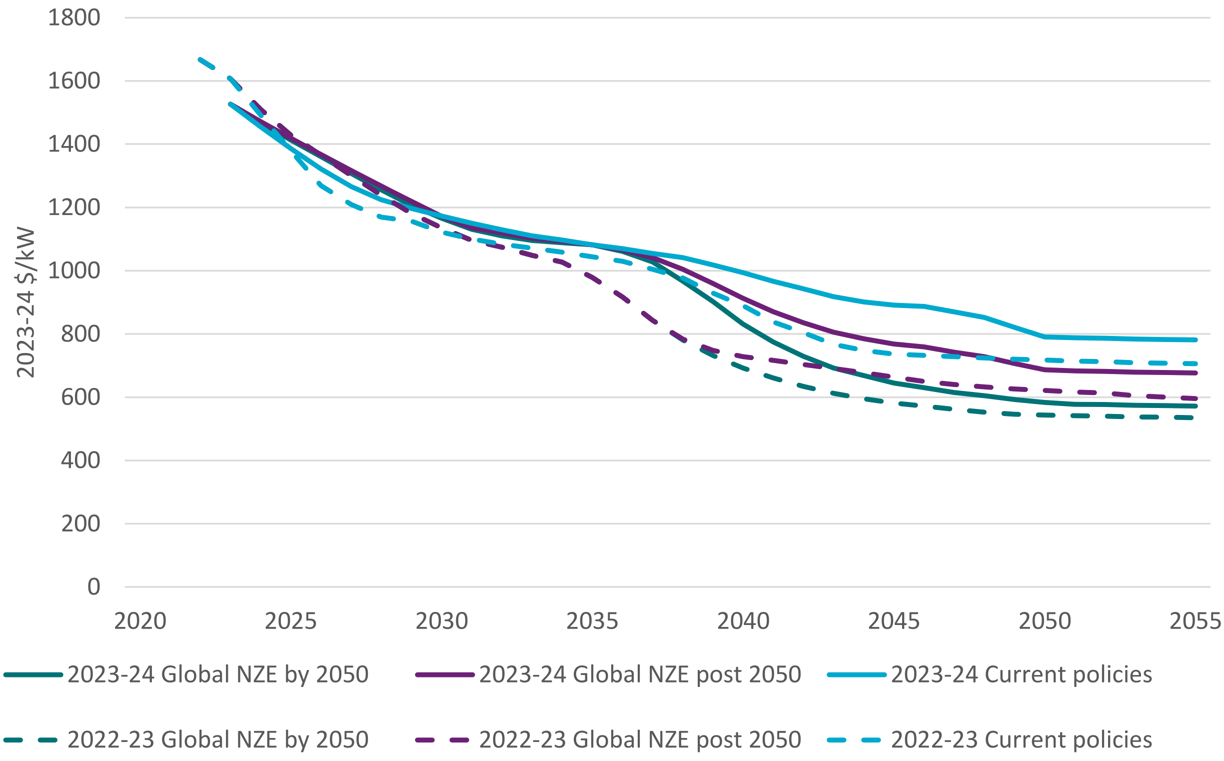

Figure 4-11 Projected capital costs for large scale solar PV by scenario compared to 2022-23 projections

4.3.10 Rooftop solar PV

The current costs for rooftop solar PV systems are lower and well aligned to the level projected for 2023 in the previous GenCost report. The price aligns to a 7kW system, but it should be noted that rooftop solar PV is sold across a broad range of prices[30]. This data is best interpreted as a mean and may not align with the lowest cost systems available.

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

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

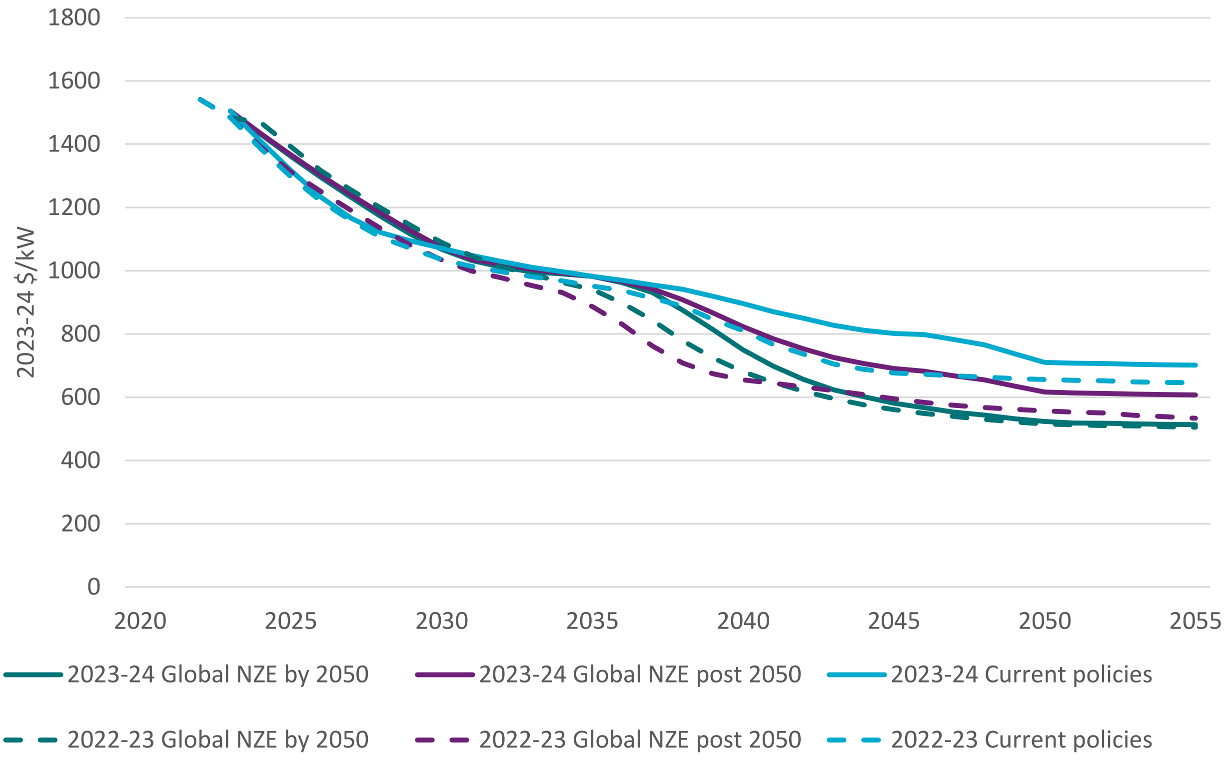

Figure 4-12 Projected capital costs for rooftop solar PV by scenario compared to 2022-23 projections

4.3.11 Onshore wind

The updated Aurecon (2024) data indicates that onshore wind has experienced an 8% increase in capital costs in 2023 (down from a 35% increase the previous year). Unlike other technologies, our assumption is that capital costs of onshore wind will not return to its normal cost path until 2035 in all scenarios. As such, costs are higher than previously projected throughout that period. After 2035, wind costs are projected to be reduced with greater global climate policy ambition and subsequent deployment. Land cost increases are assumed which will partially offset these reductions. Cost reductions are strongest under *Global NZE by 2050* resulting a range of around $1740/kW to $1910/kW by 2055.

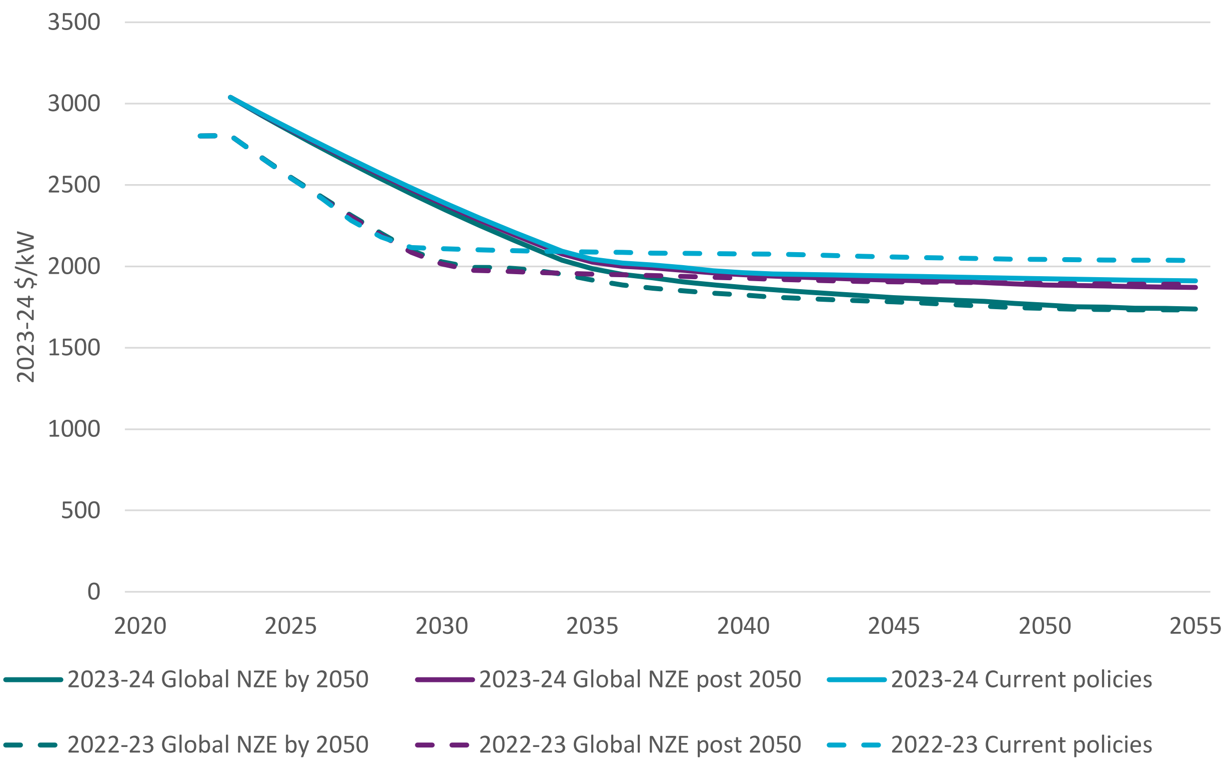

Figure 4-13 Projected capital costs for onshore wind by scenario compared to 2022-23 projections

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 siting conflicts. Fixed offshore wind is the least cost offshore technology, but its maximum deployment is limited by access to seas of a maximum depth of around 50-60 metres[31] and any navigation or marine conservation 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 2022-23. The current costs for both types of offshore wind are provided in Aurecon (2024). The updated capital costs align well with the year ahead cost reductions projected in 2022-23. Post 2023, the offshore wind capital costs are not assumed to reconnect with underlying costs prior to the global inflationary pressures until 2035. As a result, cost projections tend to be higher than projected in 2022-23 during this period.

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

In *Current policies*, floating offshore wind deployment is low. As such, the rate of cost reductions is generally low. Cost reductions are faster and deeper in the *Global NZE* scenarios where the demand for low emission electricity is higher and climate policy ambitions are stronger. Just before 2050, the cost of floating offshore wind falls below that of fixed offshore wind. This result could be plausible if we consider that, in this scenario and time period, most readily accessible fixed offshore wind sites adjacent to the highest demand countries may already be claimed shifting the focus of global manufacturing to supplying floating offshore wind technology.

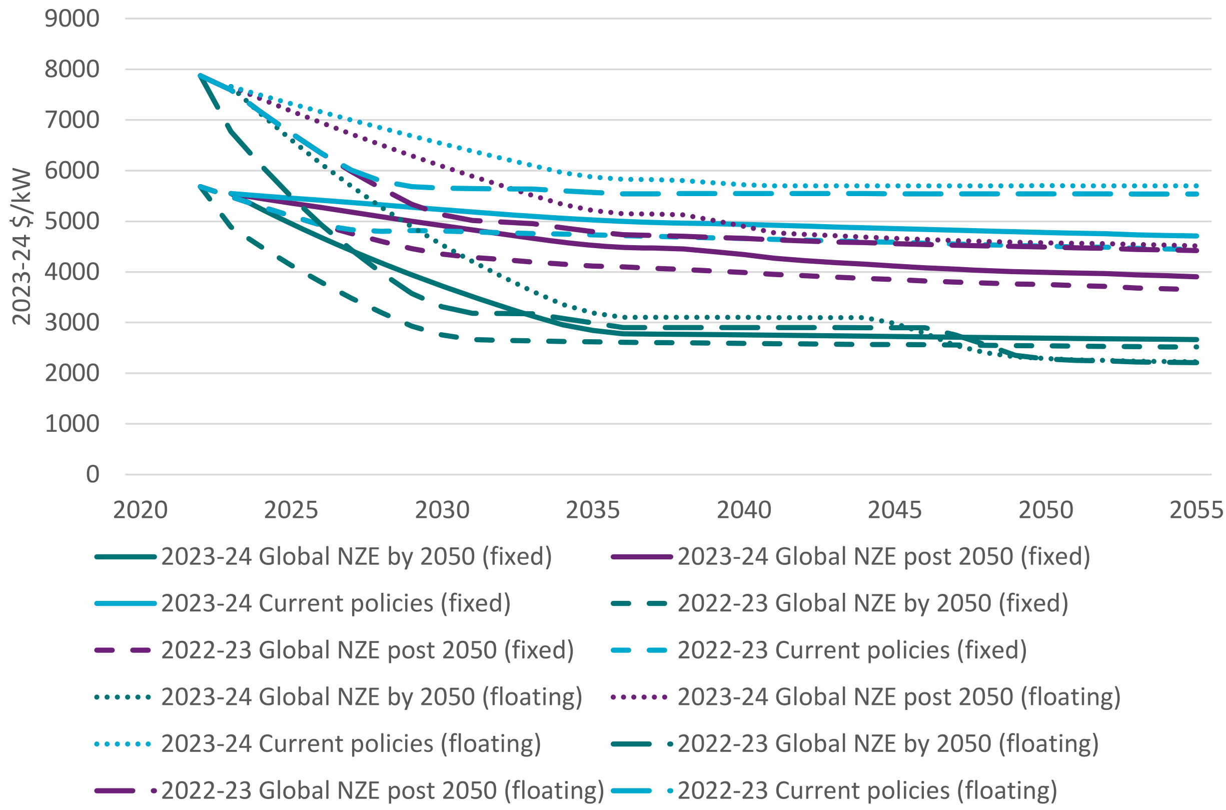

Figure 4-14 Projected capital costs for fixed and floating offshore wind by scenario compared to 2022-23 projections

4.3.13 Battery storage

The projections for batteries include a 2% increase in total costs which is reasonably well aligned with the previous projections. It is assumed that costs converge back to their underlying level pathway by 2027 in *Current policies* and by 2030 in the *Global NZE* scenarios.

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. Historical cost reductions have mainly been achieved through deployment in industries other than electricity such as in consumer electronics and electric vehicles. However, small- and large-scale stationary electricity system applications are growing globally. Under the three global scenarios, batteries have a large future role to play supporting variable renewables alongside other storage and flexible generation options and in growing electric vehicle deployment. The projected future change in total cost of battery projects is shown in Figure 4-15 (battery and balance of plant).

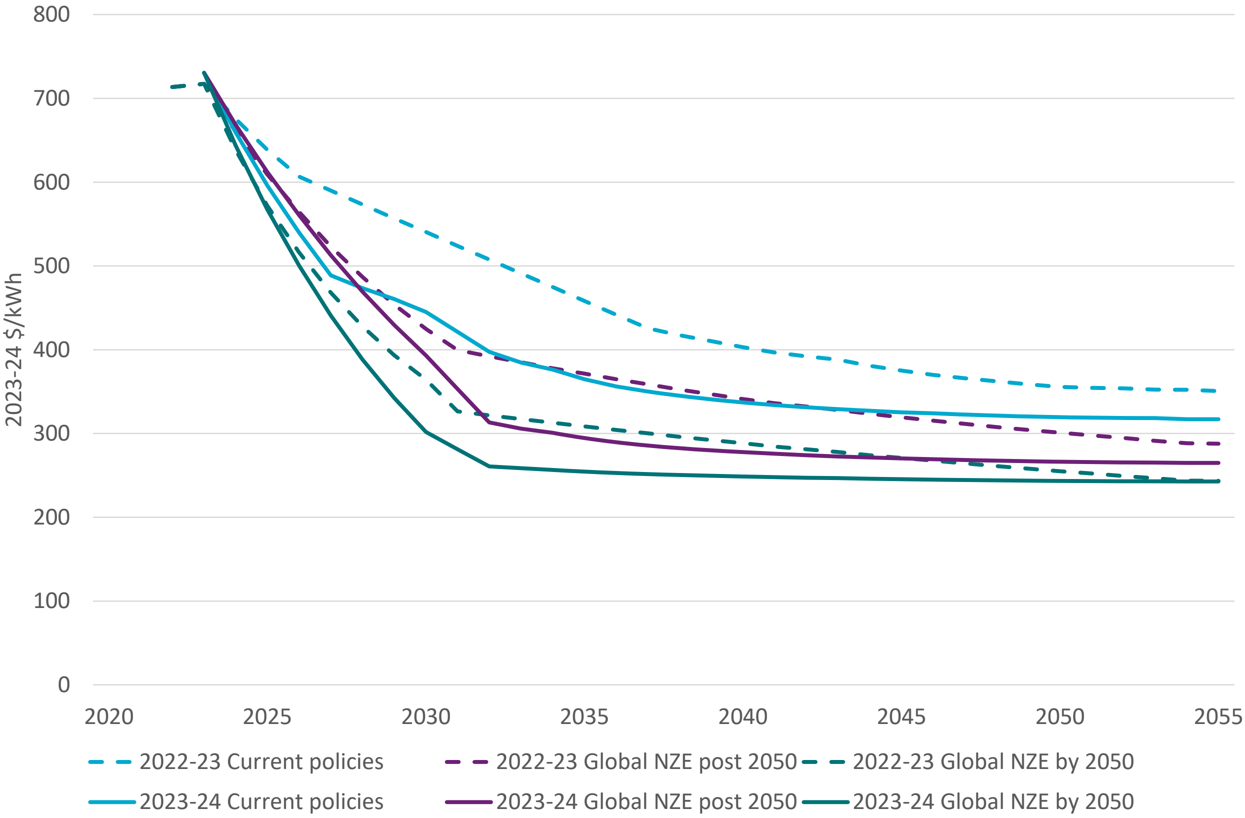

Figure 4-15 Projected total capital costs for 2-hour duration batteries by scenario (battery and balance of plant)

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

Aurecon (2024) has included current costs for small-scale batteries, designed to be installed in homes. They are estimated at $14,400 for a 5kW/10kWh system or $1455/kWh, including installation. This is around twice the cost of large-scale battery projects.

4.3.14 Pumped hydro energy storage

Pumped hydro energy storage is assumed to be a mature technology and receives the same assumed improvement rate as other mature technologies. The previous source of current cost data was the 2020-21 and 2021-22 AEMO Integrated System Plan (ISP) input and assumptions workbooks – December 2020 and June 2022 respectively. These were informed by the Entura (2018) report and adjusted for inflation. Aurecon (2024) has provided the first update in some time and capital costs have risen as a result of new information since that time. The increase in current costs is the main feature of the new projections.

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

Unlike the other technologies, all three scenarios assume costs return to normal by 2030 (rather than in 2027 for *Current policies*). This reflects the longer lead time for PHES projects which means it is unlikely the level of global climate ambition will result in different cost trajectories before 2030. Site variability is more likely a greater source of variation in costs.

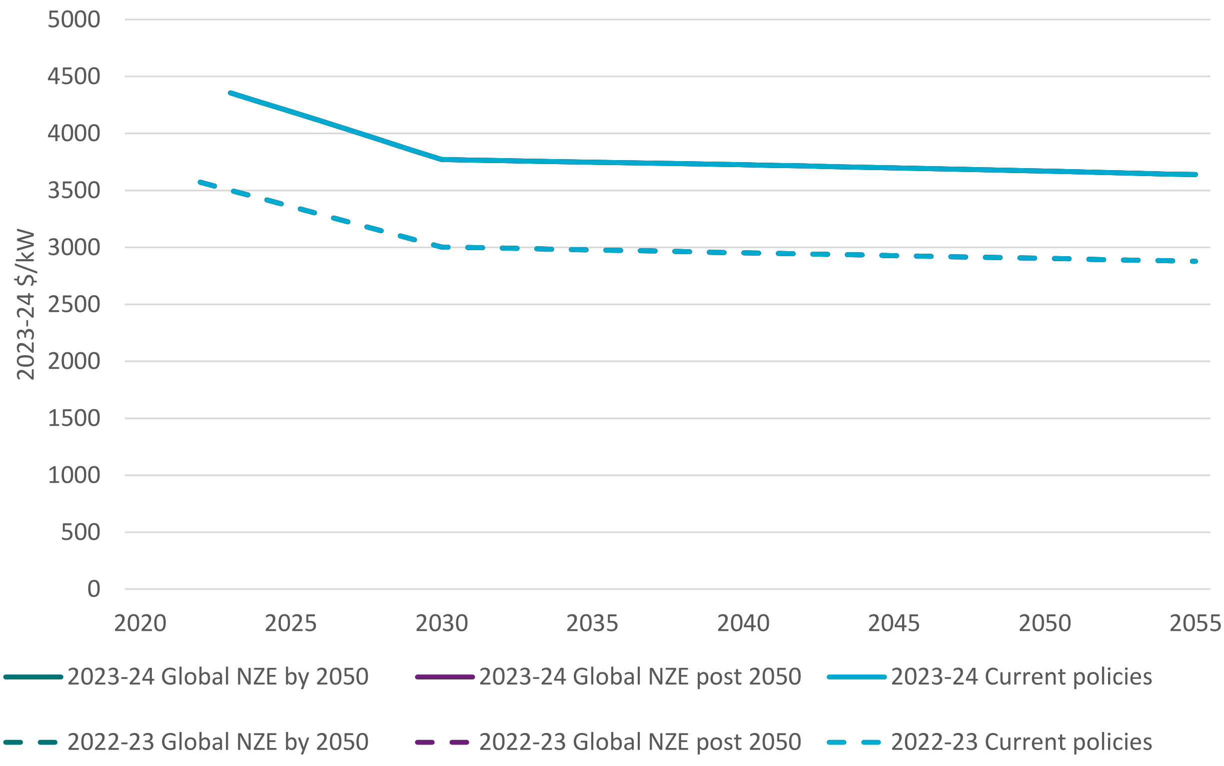

Figure 4-16 Projected capital costs for pumped hydro energy storage (12 hours) by scenario

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 with most technologies other than fuel cells increasing in capital costs. Like PHES, wave and tidal energy had not been updated for some time and so increases reflect the recent update by Aurecon (2024) rather than current inflationary pressures. Fuel cells have been updated more regularly and are well aligned with previous projections. The downward trend to either 2027 or 2030 have been included using the same methodology for other technologies. Projections also include increasing land costs.

Current policies

Biomass with CCS is not deployed in the *Current policies* scenario because the climate policy ambition is not strong enough to incentivise deployment. Cost reductions after 2027 reflect co-learning from other CCS technologies which are deployed in electricity generation and in other sectors. Fuel cell cost improvements are mainly a function of deployment and co-learning in the vehicle sector rather than in electricity generation. Neither wave nor tidal/ocean current are deployed to any significant level mainly reflecting the lack of climate policy ambition needed to drive investment in these relatively higher cost renewable generation technologies. The current costs for wave and tidal/ocean current technologies have changed significantly reflecting that the data provided by Aurecon (2024) is more up to date than previous sources.

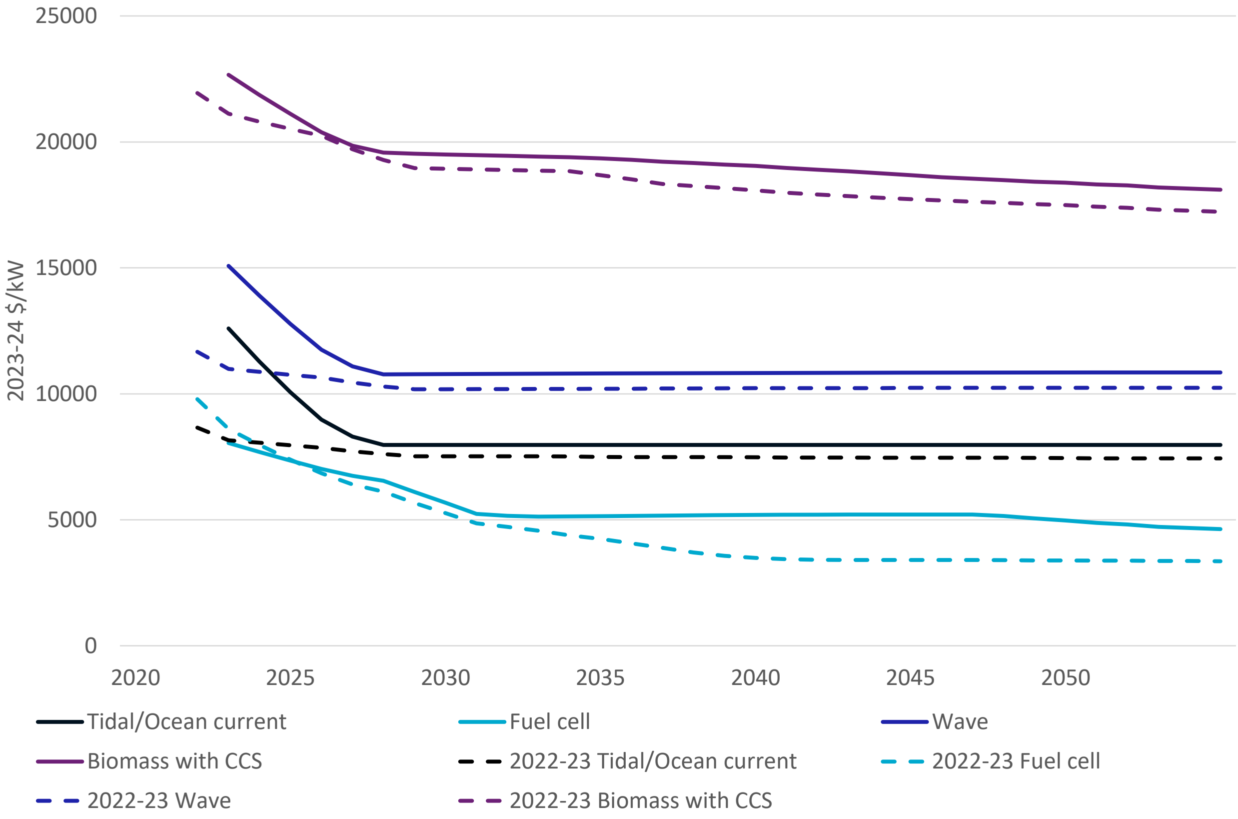

Figure 4-17 Projected technology capital costs under the *Current policies* scenario compared to 2022-23 projections

Global NZE by 2050

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

Fuel cells and wave energy are deployed although the early reduction in fuel cells reflects their use in the transport sector. Tidal/ocean current generation has minor deployment from the mid-2040s.

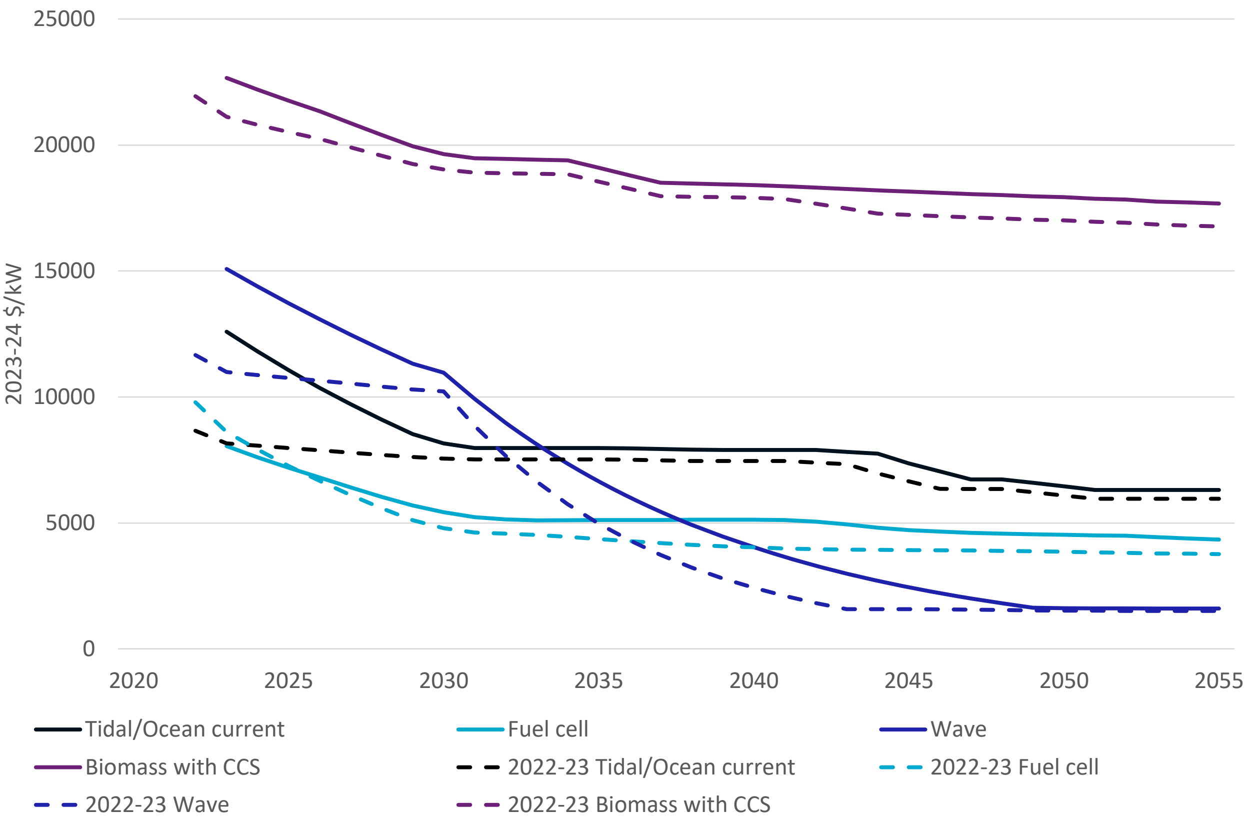

Figure 4-18 Projected technology capital costs under the *Global NZE by 2050* scenario compared to 2022-23 projections

Global NZE post 2050

Biomass with CCS is deployed at almost the same level of *Global NZE by 2050* resulting in similar cost reduction. Again, the majority of cost reductions reflect co-learning from deployment of other types of CCS generation or use of CCS in other applications. Both scenarios have significant deployment of gas with CCS generation and steam methane reforming with CCS which brings down the cost of all CCS technologies sooner compared to *Current policies*. Similar to *Current policies,* wave and tidal/ocean energy is not deployed.

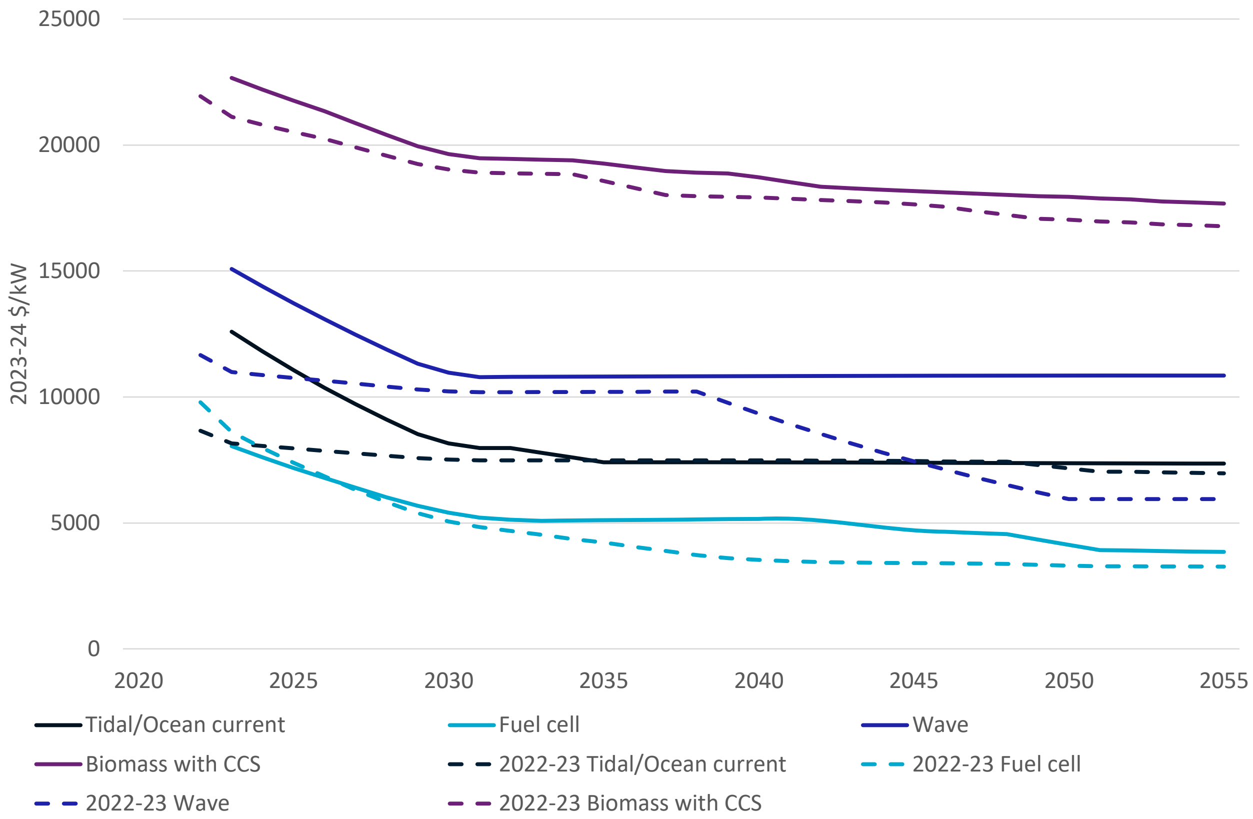

Figure 4-19 Projected technology capital costs under the *Global NZE post 2050* scenario compared to 2022-23 projections

4.3.16 Hydrogen electrolysers

Hydrogen electrolyser costs have decreased in 2023 and the decrease is sourced from Aurecon (2024). The direction of change and relative changes in 2023 are partly influenced by Aurecon (2024) changing the sources of the cost information and scale of plant and so no trend should be read into it. Alkaline electrolysers remain lower cost than proton-exchange membrane (PEM) electrolysers at present. However, PEM electrolysers have a 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.

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

The current costs applied at the starting point of the projection are for 10MW electrolysers. This scale is far smaller than we would expect to see deployed over the long term where multi-gigawatt renewable zones are being considered to supply hydrogen production hubs. No other technology in this report is presented at trial scale. We therefore adjust the scale over time in the projection to recognise electrolysers moving out of the trial stage and into full scale production. We assume full scale is 100MW. Applying typical engineering cost scaling factors this movement to full scale accounts for around an 80% reduction in costs. The electrolyser capital cost reduction rate would be significantly slower without this scale effect.

Electrolyser deployment is being supported by a substantial number of hydrogen supply and end-use subsidised deployments globally and in Australia. Experience with other emerging technologies indicates that this type of globally coincident technology deployment activity can lead to a scale-up in manufacturing which supports cost reductions through economies of scale.

Very low costs of electrolysers, at the bottom end of the projections here, have been reported in China. However, differences in engineering standards and operating and maintenance costs mean these are not able to be immediately replicated in other regions. They do indicate, however, a potentially achievable level of costs over the longer term.

Deployment of electrolysers and subsequent cost reductions are projected to be greatest in the *Global NZE by 2050* scenario. Consistent with their lower global climate policy ambition, hydrogen electrolyser production is 57% lower by 2050 in *Global NZE post 2050* and 79% lower in *Current policies*.

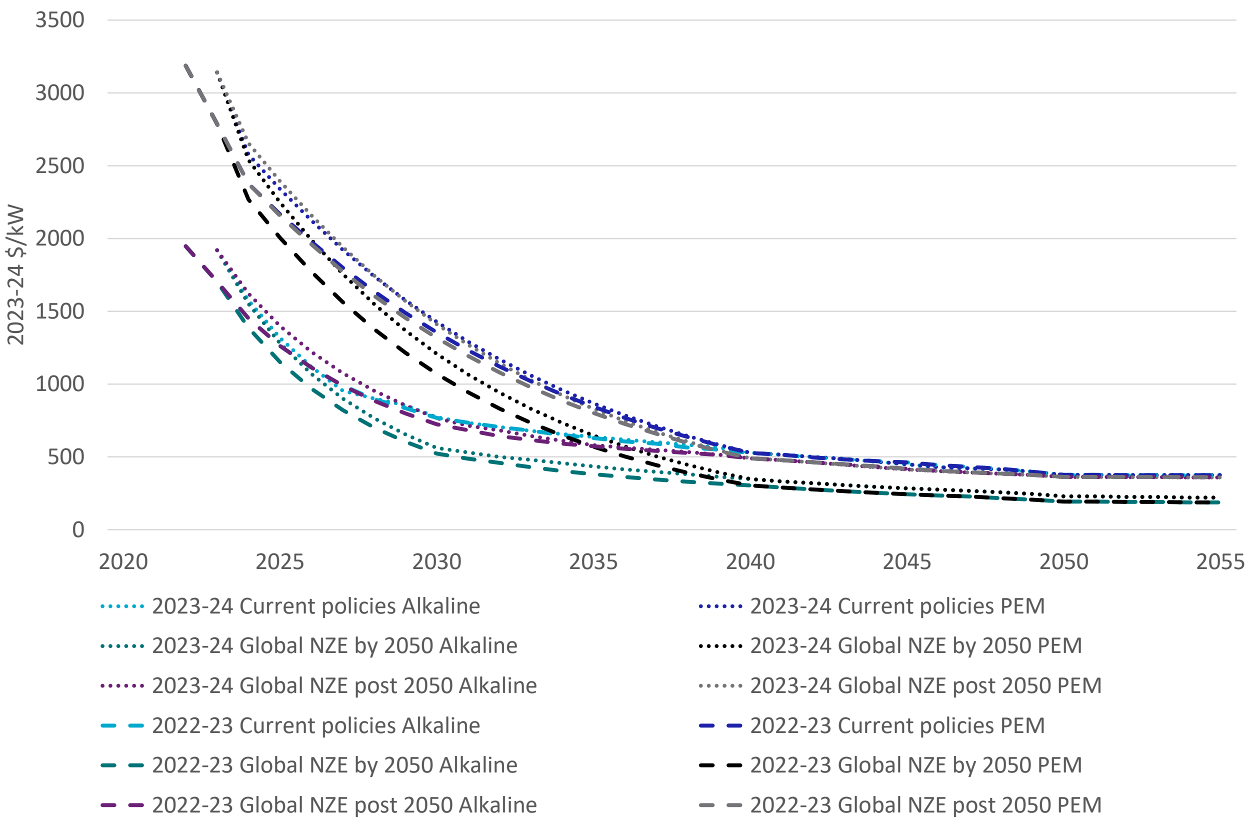

Figure 4-20 Projected technology capital costs for alkaline and PEM electrolysers by scenario, compared to 2022-23

5 Levelised cost of electricity analysis

5.1 Purpose and limitations of LCOE

Levelised cost of electricity (LCOE) data is an electricity generation technology comparison metric. It is the total unit costs a generator must recover to meet all its costs including a return on investment. Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data[32]. LCOE is a simple screening tool for quickly determining the relative competitiveness of electricity generation technologies. It is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance. Furthermore, in the GenCost 2018 report and a supplementary report on methods for calculating the additional costs of renewables (Graham, 2018), we described several issues and concerns in calculating and interpreting levelised cost of electricity. These include:

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

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

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

- Separate and group together peaking technologies, flexible technologies and variable technologies
- Included, up until the 2022-23 GenCost report, additional LCOE calculations for baseload fossil fuel technologies which added a climate policy risk premium of 5% based on Jacobs

[32] 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.

(2017). This information has been discontinued because the estimated risk premium is now considered inadequate to capture climate policy risk in a meaningful way.

5.2 LCOE estimates

5.2.1 Framework for calculating variable renewable integration costs

LCOE is typically used to compare the cost of one or more standalone projects on a common basis for a particular year (assuming they can all be built overnight, even if they have construction times varying from one to several years[33]). Technically, all electricity generation projects need other generation capacity to provide reliable electricity, even those that are dispatchable. Besides their inherent dispatchability, a key reason why the integration costs for dispatchable technologies are low is because they can rely on the flexibility of existing generation capacity to fill in at times when they are not generating or to add to generation during peak periods when they may already be at full production. The main difference with variable renewables is that existing capacity may not be enough to ensure reliable supply as the share of variable renewables grows. It may be enough when variable renewables are in the minority share of generation. However, it is not enough when they are in the majority because, to achieve their majority, significant existing flexible generation must be retired to make way for variable renewable generation.

To calculate the integration cost of variable renewables, we therefore start by allowing them free access to any existing flexible capacity (that has not retired). Next, we need to add the cost of any extra capacity the project needs to deliver reliable electricity.

In previous GenCost reports, the focus was on calculating the integration costs for 2030 and the calculation allowed renewable projects to use any capacity that was expected to be built by that time at no cost. While this approach is strictly correct for answering the question of what integration costs are relevant for someone investing in a project in 2030, feedback from stakeholders has indicated an appetite to consider the investor’s perspective at an earlier point in time when the electricity system is less developed. Consequently, this report includes integration costs for renewables in 2023 in addition to 2030.

Another concern of stakeholders is that the integration costs should include specific projects such as Snowy 2.0 and various committed or under construction transmission projects so that the community can understand how they are impacting the cost of electricity from variable renewables. Prior to 2030, there are many projects that are already committed by regulatory processes and government sponsored investments. After 2030, the investment landscape is less constrained.

In 2023, there are only negligible amounts of home battery systems and electric vehicles. Consequently, the high voltage system can only use storage that it builds for itself in 2023.

The purpose of GenCost is to provide key input data, primarily capital costs, to the electricity modelling community so that they can investigate complex questions about the electricity sector

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[33] Interest lost during construction is added so that the advantage given by projects that take less time to build is recognised.

up to the year 2055. LCOE data can only answer a narrow range of questions. It is provided for the purpose of giving stakeholders who may not have access to modelling resources an indication of the relative cost of different technologies on a common basis.

To avoid any confusion, Table 5-1 defines the question that is answered by the 2023 and 2030 LCOE data. Note that LCOE data for 2040 and 2050 is also provided, but without renewable integration costs. This reduces the computational burden for the GenCost project and recognises that, by the 2040s, if renewables are taken up, then most renewable integration resources will already be in place.

If the LCOE does not answer a stakeholder's question then they may need to commission their own modelling study. Making data available that can be used in modelling studies is the primary goal of GenCost.

Table 5-1 Questions the LCOE data are designed to answer

LCOE data	Question answered
2023 variable renewables LCOE with integration costs	Assuming any existing capacity available in 2023 is free but insufficient to provide reliable supply, what is the total unit cost an investor must recover to deliver a project that provides reliable electricity supply in 2023 from a combination of variable renewable generation, transmission, storage and other resources, including the cost of currently committed or under construction projects?
2023 LCOE of all other generation technologies	Assuming any existing capacity available in 2023 is free and sufficient to support reliable integration, what is the total unit cost an investor must recover to deliver a project that provides electricity supply in 2023?
2030 variable renewables LCOE with integration costs	Assuming any existing capacity available in 2030 is free but insufficient to provide reliable supply, what is the total unit cost an investor must recover to deliver a project that provides reliable electricity supply in 2030 from a combination of variable renewable generation, transmission, storage and other resources?
2030 LCOE of all other generation technologies	Assuming any existing capacity available in 2030 is free and sufficient to support reliable integration, what is the total unit cost an investor must recover to deliver a project that provides electricity supply in 2030?

5.2.2 Key assumptions

We calculate the integration costs of renewables in 2023 and 2030 imposing large-scale variable renewable energy (VRE) shares of 60% to 90%[34] which will require additional capacity over and above that already existing in the electricity system to ensure reliable supply. An electricity system model is applied to determine the optimal investment to support each VRE share. In practice, although wave, tidal/current and offshore wind are available as variable renewable technologies, onshore wind and large-scale solar PV are the only variable renewables deployed in the modelling due to their cost competitiveness[35].

The VRE share does not include rooftop solar PV. The impact of rooftop solar PV is accounted for, however, in the demand load shape as is the impact of other customer energy resources. Virtual Power Plants (VPPs) and electric vehicles are negligible in 2023. However, in 2030, a portion of customer-owned battery resources are assumed to be available to support the wholesale generation sector consistent with the approach taken in the AEMO ISP.

The standard LCOE formula requires an assumption of a capacity factor. Our approach in this report is to provide a high and low assumption for the capacity factor (which we report in Appendix B) in order to create a range[36]. Stakeholders have previously indicated they prefer a range rather than a single estimate of LCOE. However, it is important to note that these capacity factors are not used at all in the modelling of renewable integration costs. When modelling renewable integration costs, we use the variable renewable energy production traces published by AEMO for its Integrated System Plan. We incorporate the uncertainty in variable renewable production by modelling nine different weather years, 2011 to 2019, and the results represent the highest cost outcome from these alternate weather years.

The model covers the NEM, the South West Interconnected System (SWIS) in Western Australia (WA) and the remainder of WA. Northern Territory (NT) is not included in the results as it represents an outlier given its isolation and small size.

2023 represents the current electricity system. In 2030, we project forward including all existing state renewable energy targets resulting in a 64% renewable share and 56% variable renewable share in Australia ex-NT[37] (both excluding rooftop PV). The share fluctuates a few percent depending on the nine weather years. The counterfactual VRE share reflects the impact of existing

[34] Above 90% VRE share is of limited interest because it would mean forcibly retiring other non-variable renewables such as hydro and biomass which would not be optimal for the system. Also there is no current requirement for the electricity system to be emissions free. For example, a 95% emissions free electricity system could still be consistent with meeting Australia's 2050 net zero emission goal.

[35] This does not preclude other types of projects proceeding in reality but is a reflection of modelling inputs in 2023 and 2030.

[36] The capacity factor range assigned to new build technologies is based on a formula which uses the ten-year average capacity factors. For the high range, we use the high range of historically achieved capacity factors. However, the low range capacity factor assumption is closer to the average capacity factor rather than the lowest case. Specifically, we assume the low range value is 10% below the average on the basis that if a project cannot achieve a capacity factor at least that level it is unlikely to proceed as a new investment. Appendix D of the *GenCost 202-23: Final report* provided a discussion of historical capacity factors upon which the data in this report is based.

[37] We do not include the impact of the Capacity Investment Scheme which is a national policy for achieving 82% renewables by 2030. In the June 2022 ISP, the 82% renewables policy was consistent with 65% large-scale VRE share with the remainder of renewable share made up of hydro, biomass and rooftop solar PV (which represents small-scale VRE). As such, most of the large-scale VRE shares explored in GenCost exceed government policy to 2030 except the 60% case. We exclude the CIS policy so that the 60% case can remain and the trend in progression of costs from 60% to 90% can still be observed.

state renewable targets, planned state retirements of coal capacity in the case of WA and an already existing high VRE share in South Australia.

In both 2023 and 2030, New South Wales, Queensland, Victoria and the SWIS are the main states that are impacted by imposing the 60% to 90% VRE shares given that Tasmania and South Australia are already dominated by renewables such that the business as usual (BAU) already includes much of the necessary capacity to support high VRE shares. The NEM is an interconnected system, so we are also interested in how those states support each other and the overall costs for the NEM. The VRE share is applied in each state at the same time, but individual states can exceed the share if it is economic to do so.

As we implement higher variable renewable energy shares, we must forcibly retire coal plant (only as a modelling assumption) as meeting the variable renewable share and the minimum load requirements on coal plant would otherwise eventually become infeasible[38].

Snowy 2.0 ($12 billion) and battery of the nation ($3.3 billion) pumped hydro projects are assumed to be committed with construction complete before 2030 in the BAU, as well as various transmission expansion projects already flagged by the June 2022 ISP process to be necessary before 2030 (Table 5-2). The NSW target for an additional 2 GW of at least 8 hours duration storage is also assumed to be committed and complete by 2030 together with the Kurri Kurri gas peaking plant[39]. For the 2023 calculations, we abstract from reality and assume these projects can be completed immediately so that the cost of these committed projects is included in the current cost of integrating variable renewables[40]. These costs are included regardless of the VRE share. Pumped hydro, battery and peaking plant costs are sourced either directly from the project source or AEMO inputs and assumptions workbook (AEMO 2023a). Transmission costs are from AEMO (2023b). For the 2030 investor, all of these projects are considered free capacity in the same way that existing capacity now is free for the 2023 analysis. This approach is consistent with the aim of the LCOE analysis (Table 5-1).

Table 5-2 Committed investments by category included in the 2023 cost of integrating variable renewables

Category	$billion
Transmission	15.9
Storage	22.9
Peaking gas	1.0

For 2023, the initial generation capacity is as it is today. For 2030, the capacity needs to be increased from today due to growing demand. In the nine weather year counterfactuals, the model does not choose to build any new fossil fuel-based generation capacity by 2030 (Figure 5-1). Pumped hydro storage is also the same. The main investment response to demand growth and the different weather years is to vary wind capacity by up to 3.9GW, solar PV capacity by 2.7GW and

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

[39] The Tallawarra B gas-fired generation project is already in operation and is not included.

[40] This is necessary because the LCOE methodology is designed to annualise all project costs into a single year. It is not well suited to costing a progression of projects over multiple years. Multi-year investment problems can be studied more appropriately in intertemporal electricity system models.

large-scale batteries (VPP capacity is fixed) by 2.1GW. The capacities shown have been compared with the AEMO ISP 2030 capacity projections. The NEM coal retirements to 2030 are aligned with Step Change (June 2022 release) but the overall demand and renewable generation is lower. Wind capacity is preferred over solar PV by 2030. However, this preference is stronger in the ISP[41]. The NEM and WA total variable renewable shares are 56% and 58% on average across the weather years. The announced closure of the Muja and Collie coal-fired generators by 2029 and 2027 respectively has increased the BAU variable renewable share in WA.

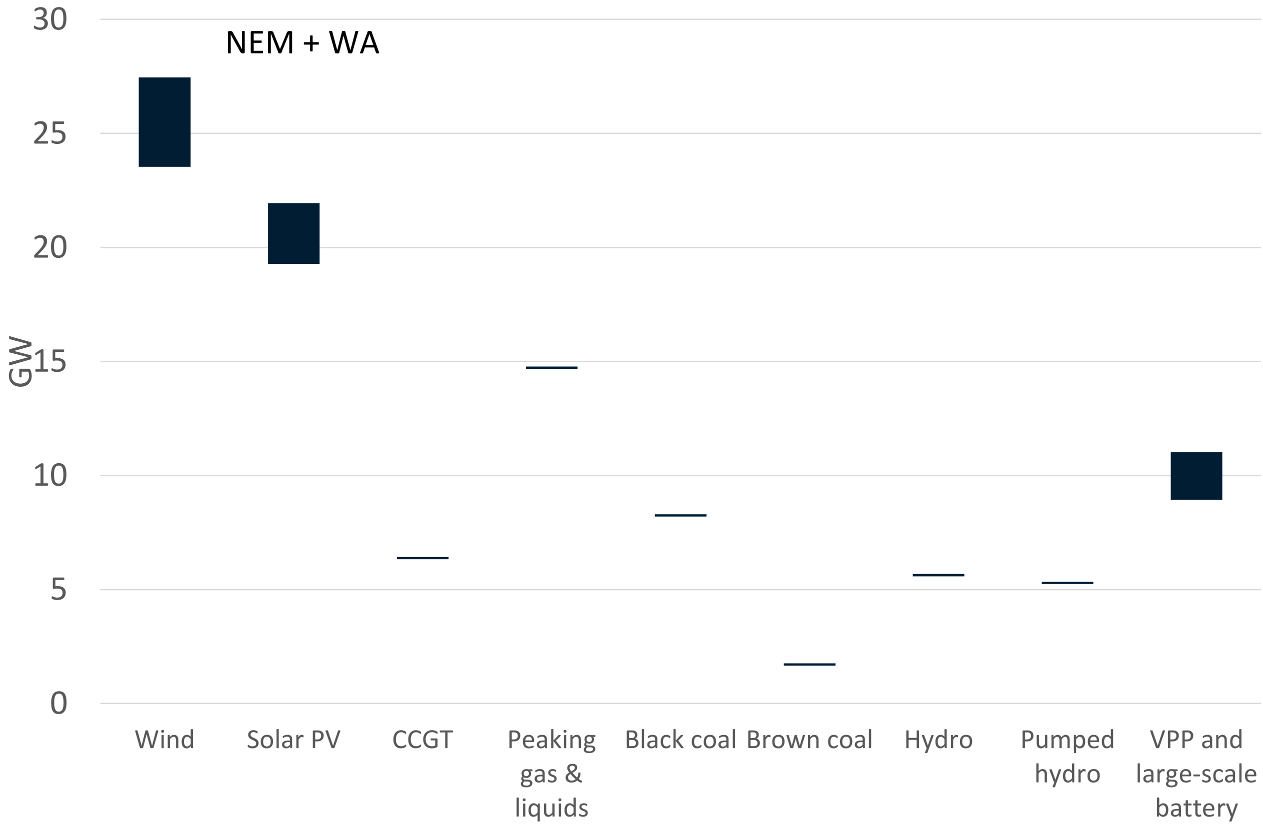

Figure 5-1 Range of generation and storage capacity deployed in 2030 across the 9 weather year counterfactuals in NEM plus Western Australia

The costs of VRE share scenarios were compared against the same counterfactual weather year to determine the additional integration costs of achieving higher VRE shares. We use the maximum cost across all weather years as the resulting integration cost on the basis that the maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation[42].

The results, shown in Figure 5-2, include storage, transmission, spillage and synchronous condenser costs where applicable. The integration costs are flat with increasing variable renewable share in the 2023 results. This is because the cost of the committed storage and

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

[42] A change for this final report is that all integration technology cost categories come from that single highest cost weather year. In previous reports each category was selected from it own highest cost weather year. However, on reflection this approach was not consistent with least cost trade-off of supporting technologies.

transmission infrastructure can be spread over more of the additional renewable generation the greater the required variable renewable share. It is appreciated that this result is somewhat counterintuitive as we normally understand that VRE integration costs increase with the VRE share. However, the result is valid and what can be learned from this result is that planned transmission and storage capacity is being built with higher electricity demand and subsequently higher volumes of variable renewable generation in mind. As the system reaches those higher VRE generation levels, the normal relationship between VRE share and costs (the higher the share the higher the costs) should resume.

Across the different VRE shares the cost of variable renewable generation in 2023 is $119/MWh on average in the NEM. This is 36% higher than average costs in 2030 for 60% VRE, but only 12% higher than average costs for 2030 for 90% VRE. Around two thirds of the higher costs are due to investors having to pay 2023 instead of 2030 technology costs (technology costs are falling over time). The remainder is due to the cost of the pre-2030 committed projects which must be paid for in the 2023 analysis, but are considered free existing capacity for investors in 2030 (in the same way that anything built pre-2023 is free existing capacity for 2023 investors).

The use of 2023 technology costs in 2023, as well as applying committed project costs to lower VRE generation than these projects were intended to support, means these results represent the highest cost for achieving these VRE shares. In reality, the transition to these VRE shares would occur over several years at higher volumes and there would be access to lower costs as technologies improve over time (see the projections in Section 4).

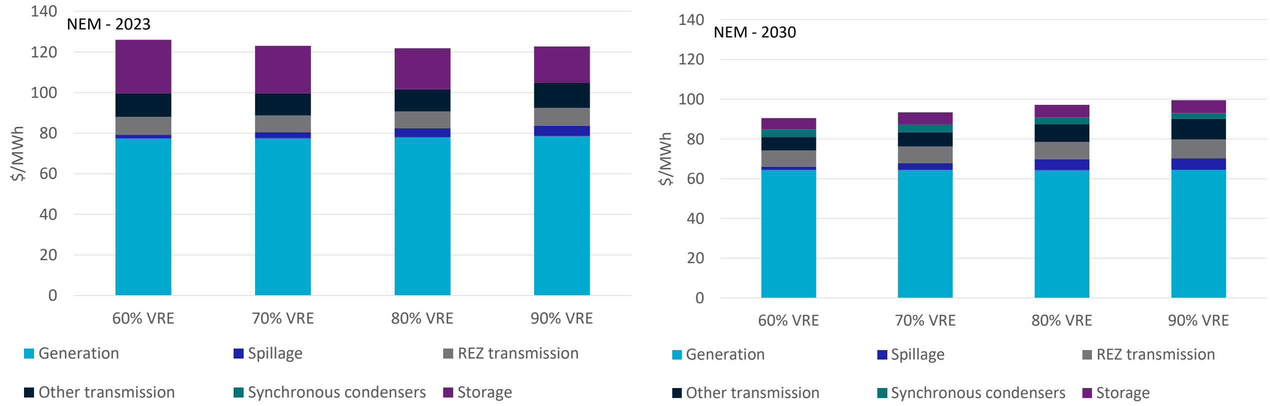

Figure 5-2 Levelised costs of achieving 60%, 70%, 80% and 90% annual variable renewable energy shares in the NEM in 2023 and in 2030

Variable renewable integration costs in 2023 are dominated by storage and transmission. Synchronous condenser costs are relatively minor reflecting that gas generation capacity remains high relative to 2023 demand and can mostly fulfill this role alongside other existing synchronous generation such as hydro (but less so coal which needs to increasingly be retired because coal's minimum run requirements make it incompatible with higher VRE shares). In 2030, with higher generation, synchronous condensers can play a larger role and expenditure is more significant. Storage is less significant by 2030 reflecting the value of investments made pre-2030 in the NEM.

Storage can shift variable renewable generation to a different time period. Transmission supports access to a greater diversity of variable renewable generation by accessing resources in other regions which can help smooth supply, reducing the need for storage. Spillage is a side-effect of over building VRE capacity to increase its minimum production levels[43]. Given the low cost of VRE capacity this is a valid alternative to expenditure of storage and transmission. As transmission, storage and VRE capacity costs are updated, their share of integration costs will change as they are partially in competition with each other.

REZ expansion costs are required at similar levels for each additional 10% increase in VRE share and in each state and across years. New South Wales and Victoria tend to attract the most transmission expenditure reflecting their central location in the NEM and access to pumped hydro storage.

Variable renewable integration costs are similar in WA but with a heavy reliance on storage given the limited ability to connect, via transmission, the various isolated systems in that state. Higher or lower costs in different states or regions are averaged out at the aggregate level for the NEM and WA. The cost of REZ transmission expansions adds an average $7.70/MWh in 2023 and $8.20/MWh in 2030, as the VRE share increases from 60% to 90%. Other transmission costs add $9.40/MWh in 2023 and $6.10/MWh in 2030. Storage costs add an average $19.40/MWh in 2023 and $10.90/MWh in 2030. Spillage costs peak at the 90% VRE share at $7.40/MWh in 2023 and $11.90/MWh in 2030.

5.2.3 Variable renewables with and without integration costs

The results for the additional costs of increasing variable renewable shares are used to update and extend our LCOE comparison figures. We expand the results for 2023 and 2030 to include a combined wind and solar PV category for different VRE shares. Integration costs to support renewables are estimated at $41/MWh to $49/MWh in 2023 and $28/MWh to $53/MWh in 2030 depending on the VRE share (Figure 5-3 and Figure 5-4).

Onshore wind and solar PV without integration costs such as transmission and storage are the lowest cost generation technologies by a significant margin. These can only be added to the system in a minority share before integration costs become significant and must be added. Offshore wind is higher cost than onshore wind but competitive with other alternative low emission generation technologies and its higher capacity factor could result in lower storage costs. Integration costs have only been calculated for onshore wind in this report given it remains the lowest cost form of wind generation.

The cost range for variable renewables with integration costs is the lowest of all new-build technology capable of supplying reliable electricity in 2023 and 2030. The cost range overlaps slightly with the lower end of the cost range for high emission coal and gas generation. However, the lower end of the range for coal and gas is only achievable if they can deliver a high capacity factor and source low cost fuel. If we exclude high emission generation options, the next most competitive generation technologies are solar thermal, gas with carbon capture and storage (CCS) and large-scale nuclear.

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[43] Spillage has been included for the first time in this report. The spilled electricity cost is calculated as the LCOE of the variable renewable generation equipment when calculated via total additional generation minus the LCOE when calculated on the basis of useful generation only (defined as the minimum additional generation needed to meet the next 10% increment of VRE share).

5.2.4 Peaking technologies

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

Hydrogen peaking plant are higher cost at present. However, their costs are expected to fall over time. This technology has zero direct greenhouse gas emissions, but may involve some upstream emissions, depending on the hydrogen production process.

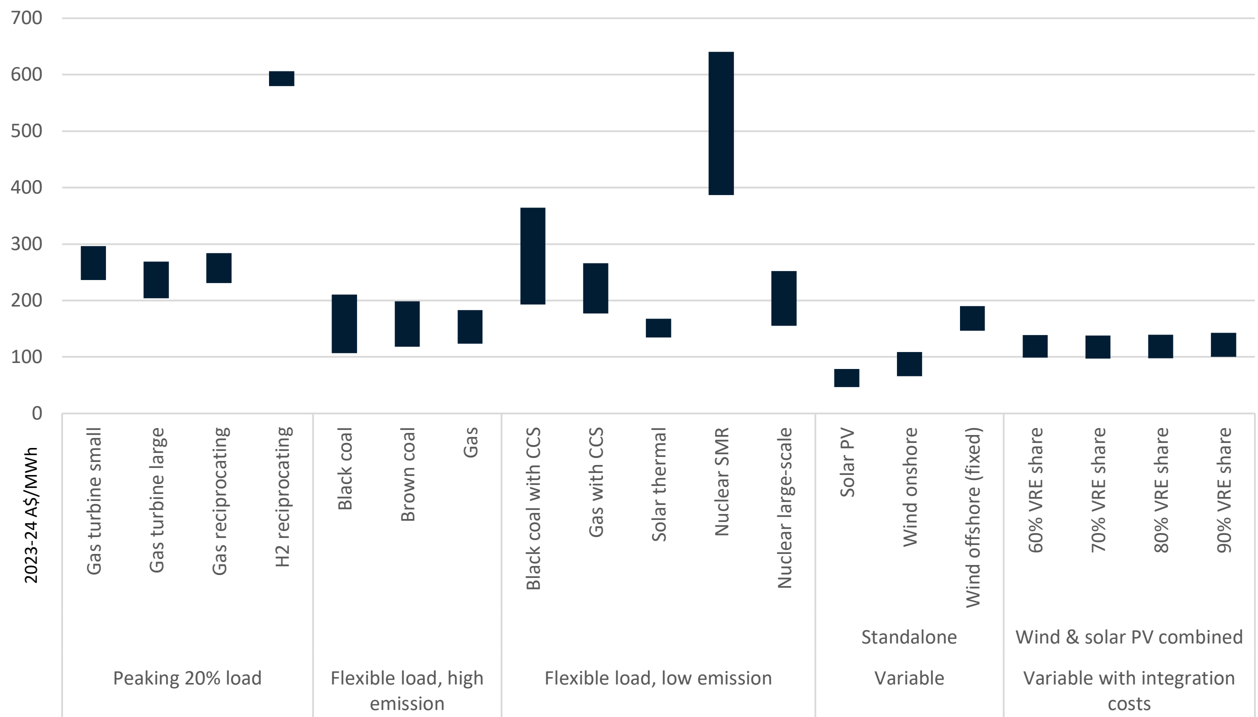


Figure 5-3 Calculated LCOE by technology and category for 2023

5.2.5 Flexible technologies

Large-scale nuclear, nuclear SMR, solar thermal, black coal, brown coal and gas-based generation technologies fall into the category of technologies that are designed to deliver energy for the majority of the year (specifically 53% to 89% in the capacity factor assumptions for most technologies and 57% to 71% for solar thermal with this exception made because higher capacity factors to do not improve costs any further for this technology).

This technology category is the next most competitive technology group after variable renewables (with or without integration costs). The reduction in fossil fuel generation costs between 2023 and 2030, is not a result of technological improvement. It represents a reduction in fuel prices and capital costs which were impacted by global inflationary pressures that peaked in 2022.

Of the fossil fuel technologies, it is difficult to say which is more competitive as it depends on the price outcome achieved in contracts for long term fuel supply. Also, using fossil fuels without carbon capture and storage makes them high emission technologies which face extra climate policy risks that are not costed here.

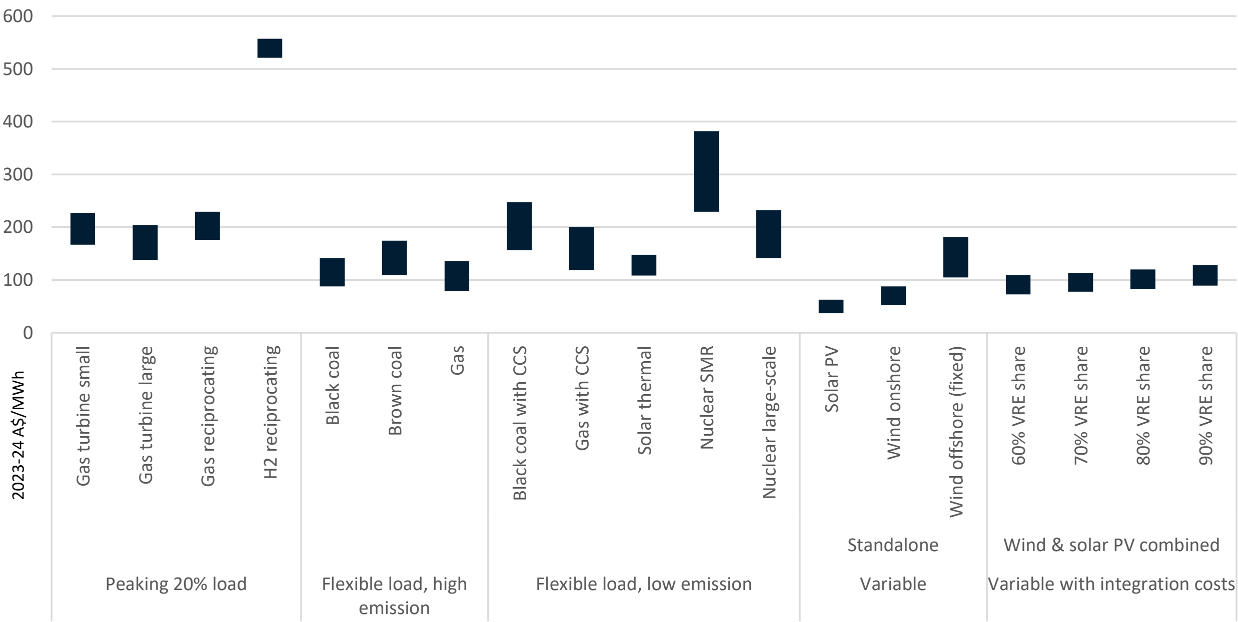


Figure 5-4 Calculated LCOE by technology and category for 2030

Low emission flexible technologies are more viable under current climate change policies. In this category, solar thermal is the most competitive technology. 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 the analysis for solar PV and wind, additional transmission costs could add around $14/MWh.

Gas with CCS is the next most competitive after solar thermal by 2030. Large-scale nuclear is newly included for this report and is only slightly higher in cost than gas with CCS. Black coal with CCS occupies a similar cost range. Nuclear small modular reactors (SMRs) are the highest cost in this category, but their cost range becomes more competitive over time. 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[44] 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%.

The historical longevity of large-scale nuclear has led many stakeholders to suggest it should have a longer amortisation period even though there is little evidence presented that private financing would be comfortable with that risk. A sensitivity case where the amortisation period for large-

[44] 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.

scale nuclear was increased from 30 years to 40 years was calculated. This results in a cost reduction for large-scale nuclear of between $9/MWh and $16/MWh. While significant, this does not appear sufficient to change its competitive position. Readers can conduct their own sensitivity analysis on this topic or any other inputs to the standard LCOE analysis if they download the GenCost Appendix tables from the CSIRO Data Access Portal[45].

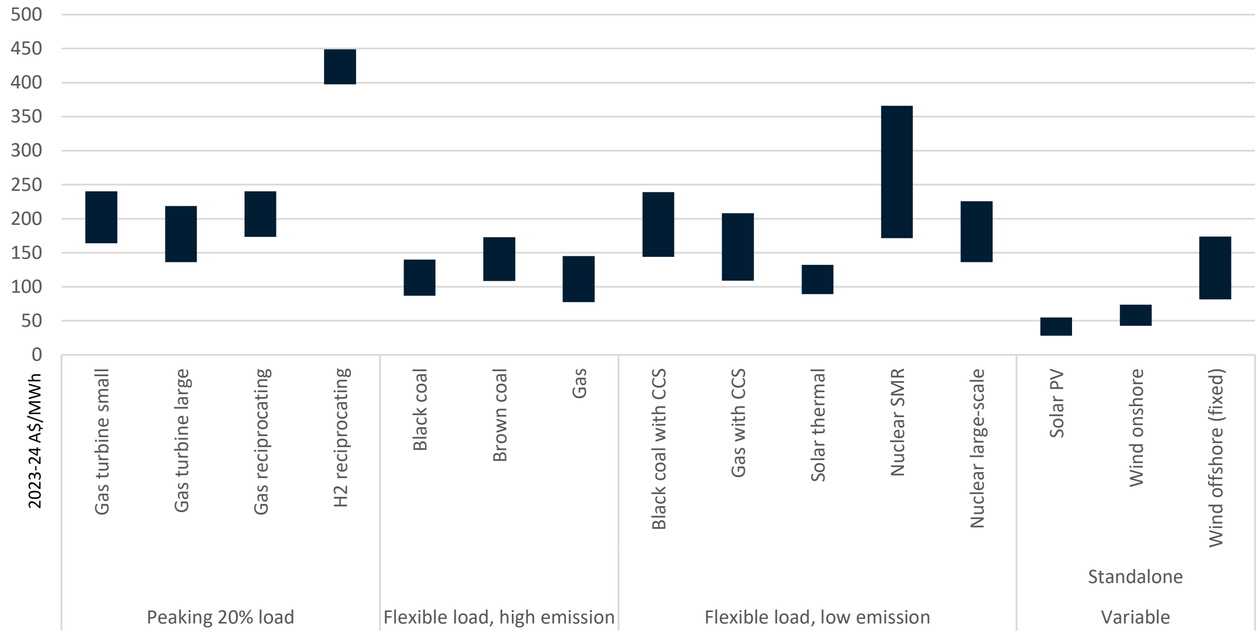


Figure 5-5 Calculated LCOE by technology and category for 2040

[45] Search for GenCost at https://data.csiro.au/

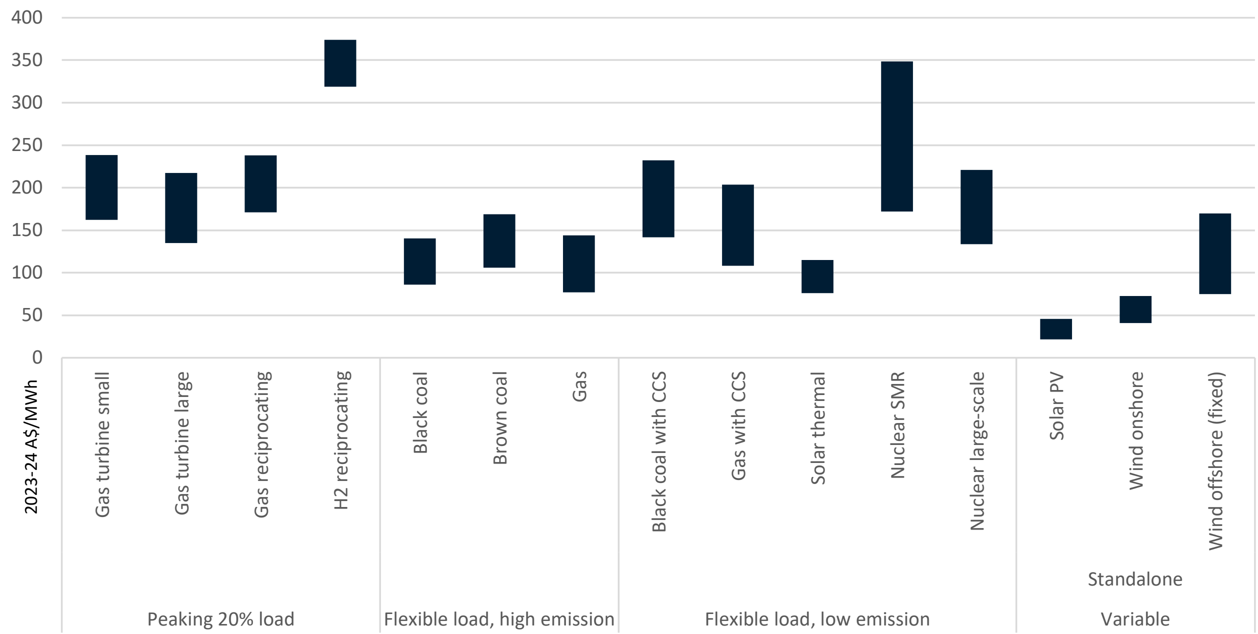


Figure 5-6 Calculated LCOE by technology and category for 2050

5.3 Storage requirements underpinning variable renewable costs

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

Variable renewables have a low capacity factor, which means their actual generation over the year expressed as a percentage of their potential generation as defined by their rated capacity, is low (e.g., 20% to 40%). The average capacity factor of coal dominated electricity supply in Australia is around 60%. As a result, to deliver the equivalent energy of coal-fired generation, the system needs to install around two times the capacity of variable renewables. If the system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has around four times the capacity needed compared to a coal dominated system. For a number of reasons, this scale of capacity development is not necessary to replace coal.

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

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

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

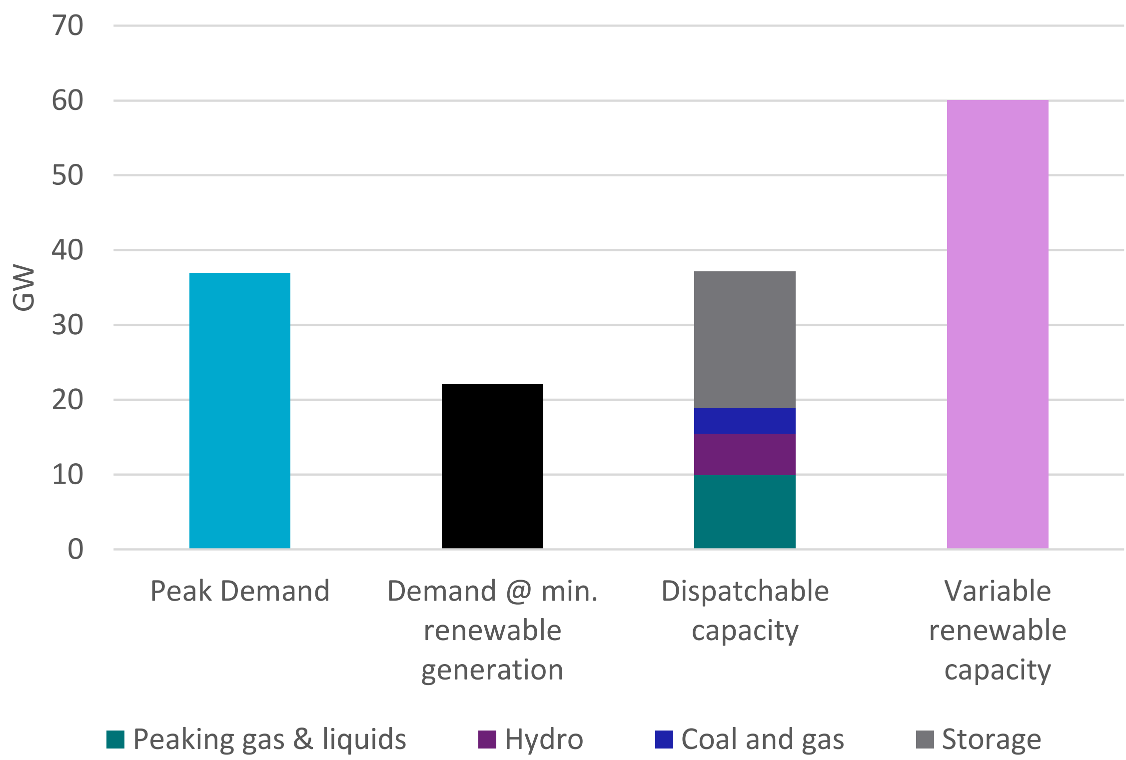


Figure 5-7 2030 NEM maximum demand, demand at lowest renewable generation and generation capacity under 90% variable renewable generation share

The modelling approach applied accounts for all of these factors across nine historical weather years. The result is that, in 2030, the NEM needs to have 0.28kW to 0.4kW storage capacity for each kW of variable renewable generation installed[46]. Showing the most extreme case of 90% variable renewable share for the NEM, Figure 5-7 shows maximum annual demand, demand when renewable generation is lowest, storage capacity, peaking capacity, other flexible capacity and total variable renewable generation capacity.

The data shows that:

- Demand at the point of lowest renewable generation[47] is substantially lower than maximum demand and can mostly be met by non-storage technologies (although in this example renewable generation is not zero and can still contribute)
- Existing and new flexible capacity is very slightly lower than maximum demand. This indicates that there is some variable renewable generation available at peak demand events in at least one state of the NEM (mostly likely wind generation if the peak occurs outside of daylight hours such as in the evening or early morning)
- Flexible capacity exceeds demand at minimum renewable generation
- The required existing and new flexible capacity to support variable renewables is a fraction of total variable renewable capacity.

[46] This ratio may change as storage and transmission are partial competitors and as such the storage ratio could increase if transmission becomes relatively more expensive. There has been a drift upwards in the ratio projected over the past few years of analysis.

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

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 & Graham, 2017; Hayward & Graham, 2013; Hayward, Foster, Graham, & Reedman, 2017).

A.1.1 Endogenous technology learning

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

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

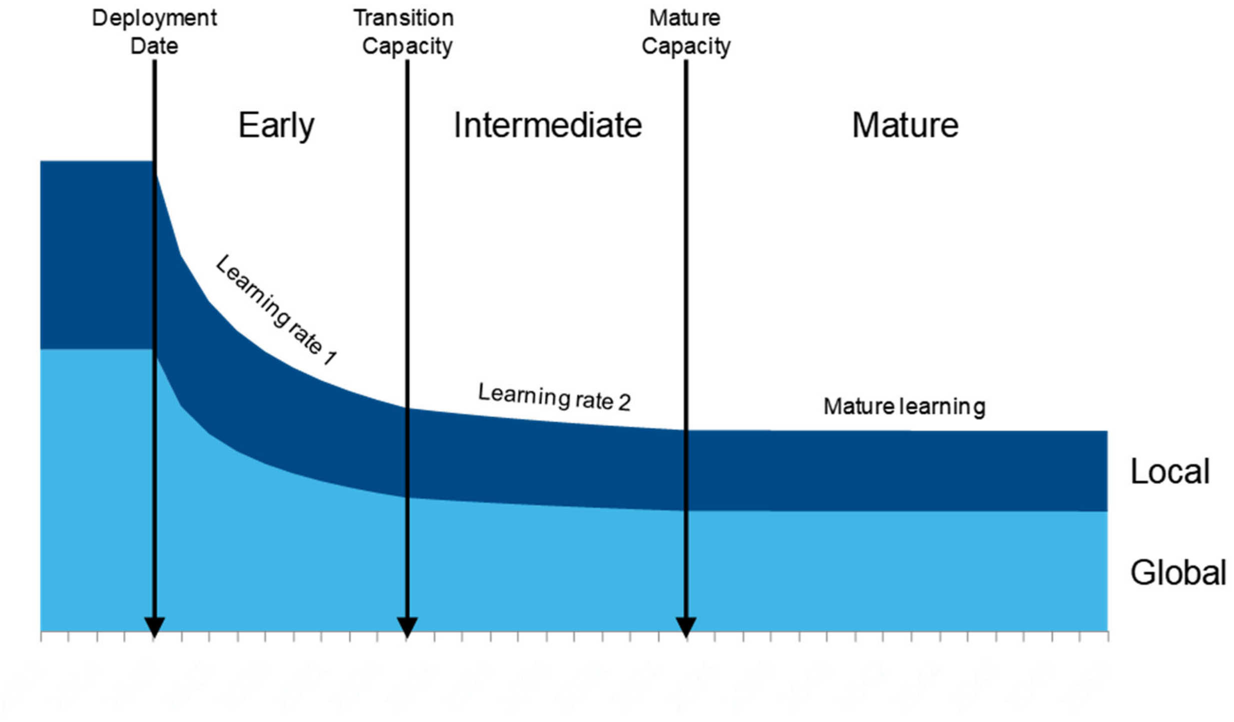
or equivalently $$\log(IC) = \log(IC_0) - b(\log(CC) - \log(CC_0))$$

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

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

(typically quoted as a percentage ranging from 0 to 50%) and the progress ratio is given by PR=100-LR. All three quantities express a measure of the decline in unit cost with learning or experience. This relationship 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 do not have a standard unit size and can be used in a variety of applications tend to have a higher learning rate for longer (Wilson, 2012). This is the case for solar photovoltaics, 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 on the cost reductions as each region will have a different level of demand for a technology and this will affect its uptake.

A.1.2 The modelling framework

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

The objective of the model is to minimise the total system costs while meeting demand and all constraints. The model is solved as a mixed integer linear program. The experience curves are segmented into step functions and the location on the experience curves (i.e., cost vs. cumulative capacity) is determined at each time step. See Hayward 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 Mature technologies and the "basket of costs"

There are three main drivers of mature technology costs: imported materials and equipment, domestic materials and equipment, and labour. The indices of these drivers over the last 20 years (ABS data) combined with the split in capital cost of mature technologies between imported equipment, domestic equipment and labour (BREE, 2012) was used to calculate an average rate of change in technology costs: - 0.35%. This value has been applied as an annual capital cost reduction factor to mature technologies and to operating and maintenance costs.

A.1.4 Offshore wind

Offshore wind has been divided into fixed and floating foundation technologies. IRENA (2022) and Stehly & 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 Aurecon (2024) 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 2023 is mostly sourced from Aurecon (2024) and is aligned to the middle of that calendar year or the beginning of the 2023-24 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.

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

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 (14hrs)	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
2023	5616	11407	8671	2126	1684	1059	5079	1908	2134	8294	22666	1526	1505	6153	3038	5545	7658	15081	28581	12590	8052	8655
2024	5485	10965	8358	2023	1619	1021	4803	1886	2155	8189	21863	1454	1409	6024	2938	5499	7488	13896	25508	11281	7689	8446
2025	5364	10550	8064	1926	1559	985	4544	1867	2178	8096	21110	1386	1318	5899	2842	5456	7323	12778	22689	10064	7349	8253
2026	5248	10153	7782	1835	1501	948	4300	1849	2203	8006	20388	1321	1232	5759	2749	5413	7162	11751	20186	8979	7026	8066
2027	5162	9861	7577	1770	1459	908	4125	1832	2213	7934	19854	1266	1166	5629	2657	5367	6999	11090	18368	8297	6744	7921
2028	5124	9707	7469	1737	1437	868	4035	1822	2216	7905	19572	1224	1120	5514	2568	5321	6840	10776	17140	7976	6545	7842
2029	5133	9688	7455	1734	1435	866	4026	1818	2212	7918	19534	1196	1094	5401	2482	5275	6685	10781	16442	7976	6101	7827
2030	5141	9675	7441	1731	1432	865	4024	1815	2208	7931	19504	1173	1071	5301	2399	5230	6533	10785	15959	7976	5676	7813
2031	5148	9663	7428	1727	1429	863	4023	1812	2204	7945	19475	1150	1049	5210	2318	5186	6385	10789	15748	7976	5239	7799
2032	5156	9652	7415	1724	1427	861	4022	1808	2200	7959	19447	1129	1029	5127	2240	5141	6240	10794	15776	7976	5163	7785
2033	5164	9642	7402	1721	1424	860	4022	1805	2196	7973	19420	1111	1010	5051	2165	5098	6099	10799	15803	7976	5124	7771
2034	5171	9631	7389	1718	1422	858	4021	1802	2192	7987	19393	1097	997	4980	2093	5054	5961	10803	15832	7976	5134	7758
2035	5178	9603	7376	1715	1419	857	4001	1799	2189	8001	19348	1082	982	4913	2045	5020	5870	10808	15677	7976	5144	7745
2036	5184	9564	7364	1713	1417	856	3971	1796	2185	8016	19291	1069	969	4851	2020	4996	5826	10813	15521	7976	5155	7732
2037	5189	9513	7352	1710	1415	854	3926	1793	2181	8031	19219	1054	954	4792	2008	4981	5824	10818	15366	7976	5165	7719
2038	5196	9477	7340	1707	1413	853	3897	1790	2178	8047	19165	1041	941	4736	1992	4966	5803	10823	15395	7976	5176	7707
2039	5201	9433	7329	1704	1410	851	3861	1787	2175	8062	19103	1018	919	4682	1972	4951	5760	10828	15425	7976	5187	7695
2040	5205	9396	7318	1702	1408	850	3831	1785	2171	8078	19048	994	896	4615	1962	4936	5722	10834	15337	7976	5198	7683
2041	5201	9344	7296	1697	1404	848	3793	1780	2165	8083	18965	966	871	4533	1953	4919	5701	10835	15228	7976	5202	7661
2042	5197	9305	7275	1692	1400	845	3770	1774	2158	8087	18897	943	849	4440	1950	4903	5701	10837	15119	7976	5205	7638
2043	5195	9270	7254	1687	1396	843	3750	1769	2152	8092	18833	918	827	4353	1946	4886	5701	10838	15128	7976	5208	7616
2044	5190	9223	7233	1682	1392	840	3718	1764	2146	8097	18756	901	811	4271	1943	4870	5701	10840	15137	7976	5212	7594
2045	5185	9176	7211	1677	1388	838	3685	1759	2140	8102	18678	891	802	4193	1940	4853	5701	10842	15145	7976	5215	7572
2046	5178	9129	7190	1672	1384	835	3653	1754	2133	8106	18602	887	798	4120	1937	4837	5701	10843	15154	7976	5215	7550
2047	5172	9097	7170	1667	1380	833	3637	1749	2127	8111	18541	870	782	4051	1934	4821	5701	10845	15163	7976	5212	7528
2048	5164	9066	7149	1663	1376	831	3621	1744	2121	8116	18482	852	766	3986	1931	4805	5701	10846	15173	7976	5156	7506
2049	5155	9032	7128	1658	1372	828	3603	1739	2115	8121	18420	821	737	3923	1927	4789	5701	10848	15095	7976	5063	7484
2050	5149	9011	7116	1655	1369	826	3590	1735	2111	8126	18382	791	710	3878	1924	4778	5701	10850	14478	7976	4974	7462
2051	5139	8976	7091	1649	1365	826	3574	1729	2104	8126	18314	788	708	3832	1920	4762	5701	10850	14359	7976	4875	7436
2052	5134	8956	7074	1645	1361	820	3566	1725	2099	8126	18272	787	706	3787	1918	4750	5701	10850	14245	7976	4817	7410
2053	5125	8916	7041	1638	1355	820	3552	1717	2089	8126	18189	784	704	3743	1915	4728	5700	10850	14074	7976	4718	7384
2054	5120	8897	7025	1634	1352	814	3546	1713	2084	8126	18149	783	703	3699	1913	4717	5700	10850	14074	7976	4678	7358
2055	5116	8878	7008	1630	1349	814	3539	1709	2079	8126	18108	781	702	3655	1911	4706	5699	10850	14074	7976	4638	7345

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 (14hrs)	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
2023	5616	11407	8236	2126	1684	1059	5079	1908	2134	8294	22666	1526	1505	6153	3038	5545	7658	15081	28581	12590	8052	8655
2024	5547	11148	8342	2065	1646	1036	4916	1895	2145	8239	22194	1469	1432	5952	2931	5243	7118	14388	26316	11812	7609	8545
2025	5488	10908	8319	2009	1611	1014	4764	1884	2160	8197	21762	1414	1362	5710	2828	4953	6606	13721	24206	11066	7193	8449
2026	5430	10676	8155	1955	1577	993	4617	1875	2174	8158	21343	1361	1295	5488	2729	4680	6131	13085	22270	10368	6802	8355
2027	5356	10416	7971	1896	1540	968	4461	1860	2183	8093	20868	1308	1232	5315	2631	4419	5686	12470	20425	9713	6411	8238
2028	5283	10164	7790	1839	1503	943	4311	1845	2191	8029	20403	1256	1171	5149	2537	4172	5273	11884	18734	9100	6042	8122
2029	5212	9917	7614	1784	1467	918	4166	1830	2199	7966	19950	1207	1114	4958	2445	3940	4890	11326	17184	8525	5694	8008
2030	5168	9751	7494	1747	1443	893	4070	1819	2204	7896	19642	1166	1068	4768	2358	3720	4536	10964	15773	8155	5427	7928
2031	5150	9663	7428	1727	1429	867	4023	1812	2204	7820	19475	1131	1032	4603	2273	3512	4206	9921	14636	7976	5228	7881
2032	5159	9652	7415	1724	1427	866	4022	1808	2200	7733	19447	1110	1011	4482	2191	3316	3901	8978	13978	7976	5142	7867
2033	5168	9642	7402	1721	1424	864	4022	1805	2196	7651	19420	1095	997	4368	2113	3131	3618	8124	13752	7976	5102	7853
2034	5177	9631	7389	1718	1422	863	4021	1802	2192	7570	19393	1089	989	4272	2037	2957	3356	7352	13467	7976	5110	7840
2035	5187	9366	7376	1715	1419	861	3758	1799	2189	7502	19099	1082	982	4174	1986	2840	3186	6653	13078	7975	5116	7827
2036	5196	9099	7364	1713	1417	860	3491	1796	2185	7456	18802	1061	962	4091	1950	2780	3103	6021	12687	7955	5120	7814
2037	5206	8830	7352	1710	1415	859	3223	1793	2181	7441	18503	1028	931	4006	1929	2772	3101	5448	12607	7930	5123	7801
2038	5216	8814	7340	1707	1413	857	3217	1790	2178	7431	18473	967	875	3928	1904	2766	3101	4930	12631	7906	5124	7789
2039	5226	8803	7329	1704	1410	856	3212	1787	2175	7425	18443	902	814	3830	1886	2760	3100	4462	12656	7902	5125	7776
2040	5236	8792	7318	1702	1408	855	3209	1785	2171	7419	18414	832	750	3731	1871	2755	3100	4038	12680	7902	5127	7764
2041	5239	8769	7296	1697	1404	852	3200	1780	2165	7424	18361	775	698	3620	1858	2749	3098	3653	12688	7902	5122	7742
2042	5243	8745	7275	1692	1400	850	3193	1774	2158	7428	18309	729	657	3525	1844	2743	3097	3305	12695	7902	5054	7719
2043	5246	8722	7254	1687	1396	847	3186	1769	2152	7432	18258	693	624	3425	1830	2737	3096	2990	12703	7827	4943	7696
2044	5249	8698	7233	1682	1392	845	3179	1764	2146	7437	18207	668	601	3347	1819	2731	3095	2705	12710	7752	4806	7674
2045	5252	8676	7211	1677	1388	842	3173	1759	2140	7441	18157	645	581	3273	1807	2725	2980	2447	12717	7362	4716	7652
2046	5255	8653	7190	1672	1384	840	3167	1754	2133	7446	18108	630	567	3213	1800	2718	2787	2213	12725	7047	4656	7629
2047	5258	8631	7170	1667	1380	837	3161	1749	2127	7450	18059	615	553	3155	1792	2711	2551	2002	12733	6732	4611	7607
2048	5261	8609	7149	1663	1376	835	3155	1744	2121	7455	18010	605	543	3102	1785	2704	2405	1812	12740	6732	4577	7585
2049	5264	8587	7128	1658	1372	832	3149	1739	2115	7459	17961	592	532	3050	1773	2696	2325	1639	12748	6594	4548	7563
2050	5268	8575	7116	1655	1369	830	3146	1735	2111	7464	17932	583	524	3007	1763	2691	2289	1623	12756	6455	4532	7541
2051	5268	8548	7091	1649	1365	830	3138	1729	2104	7464	17873	578	519	2964	1752	2684	2265	1615	12266	6317	4508	7515
2052	5268	8530	7074	1645	1361	824	3134	1725	2099	7464	17834	577	518	2922	1749	2681	2255	1612	11776	6317	4492	7489
2053	5268	8495	7041	1638	1355	824	3124	1717	2089	7464	17756	574	516	2880	1743	2673	2239	1606	11286	6317	4431	7462
2054	5268	8477	7025	1634	1352	818	3119	1713	2084	7464	17717	573	515	2839	1741	2670	2231	1604	11286	6317	4387	7436
2055	5268	8459	7008	1630	1349	818	3114	1709	2079	7464	17678	572	513	2798	1739	2666	2224	1602	11286	6317	4342	7423

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 (14hrs)	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
2023	5616	11407	8671	2126	1684	1059	5079	1908	2134	8294	22666	1526	1505	6153	3038	5545	7658	15081	28581	12590	8052	8655
2024	5547	11148	8487	2065	1646	1036	4916	1895	2145	8244	22194	1471	1434	5952	2936	5451	7413	14388	26316	11812	7605	8545
2025	5488	10908	8319	2009	1611	1014	4764	1884	2160	8206	21762	1419	1366	5710	2838	5360	7177	13721	24206	11066	7185	8449
2026	5430	10676	8155	1955	1577	993	4617	1875	2174	8170	21343	1368	1302	5488	2743	5271	6948	13085	22270	10368	6791	8355
2027	5356	10416	7971	1896	1540	968	4461	1860	2183	8109	20868	1317	1240	5315	2649	5179	6722	12470	20425	9713	6396	8238
2028	5283	10164	7790	1839	1503	943	4311	1845	2191	8049	20403	1267	1181	5194	2558	5089	6503	11884	18734	9100	6024	8122
2029	5212	9917	7614	1784	1467	918	4166	1830	2199	7989	19950	1220	1125	5094	2471	5001	6292	11326	17184	8525	5675	8008
2030	5168	9751	7494	1747	1443	893	4070	1819	2204	7954	19642	1172	1073	4968	2386	4914	6087	10964	15773	8155	5407	7928
2031	5150	9663	7428	1727	1429	867	4023	1812	2204	7943	19475	1136	1036	4818	2305	4829	5889	10789	14636	7976	5211	7881
2032	5159	9652	7415	1724	1427	866	4022	1808	2200	7956	19447	1120	1020	4657	2226	4745	5697	10794	13581	7976	5128	7867
2033	5168	9642	7402	1721	1424	864	4022	1805	2196	7970	19420	1103	1003	4515	2150	4663	5512	10799	12955	7787	5090	7853
2034	5177	9631	7389	1718	1422	863	4021	1802	2192	7984	19393	1093	993	4397	2076	4582	5333	10803	12579	7598	5100	7840
2035	5187	9528	7376	1715	1419	861	3921	1799	2189	7998	19264	1082	982	4301	2027	4522	5211	10808	12397	7409	5110	7827
2036	5196	9407	7364	1713	1417	860	3803	1796	2185	8013	19115	1065	966	4229	2001	4488	5149	10813	12215	7409	5120	7814
2037	5206	9282	7352	1710	1415	859	3679	1793	2181	8028	18961	1041	942	4162	1991	4472	5139	10818	11739	7409	5131	7801
2038	5216	9249	7340	1707	1413	857	3654	1790	2178	8043	18910	1004	908	4105	1976	4453	5128	10823	11469	7409	5141	7789
2039	5226	9231	7329	1704	1410	856	3644	1787	2175	8059	18876	960	867	4044	1959	4401	5017	10828	11197	7408	5152	7776
2040	5236	9095	7318	1702	1408	855	3514	1785	2171	8071	18722	913	823	3994	1949	4339	4899	10834	11219	7407	5163	7764
2041	5239	8937	7296	1697	1404	852	3372	1780	2165	8021	18535	871	785	3934	1941	4268	4773	10835	11222	7405	5166	7742
2042	5243	8777	7275	1692	1400	850	3229	1774	2158	7970	18347	836	753	3871	1934	4224	4741	10837	11225	7402	5094	7719
2043	5246	8741	7254	1687	1396	847	3208	1769	2152	7923	18282	805	725	3806	1926	4185	4712	10838	11228	7399	4972	7696
2044	5249	8712	7233	1682	1392	845	3195	1764	2146	7925	18226	785	706	3746	1920	4151	4687	10840	11234	7395	4821	7674
2045	5252	8686	7211	1677	1388	842	3186	1759	2140	7927	18173	768	691	3693	1915	4114	4660	10842	11241	7393	4722	7652
2046	5255	8662	7190	1672	1384	840	3178	1754	2133	7929	18121	759	682	3629	1912	4082	4637	10843	11248	7392	4652	7629
2047	5258	8639	7170	1667	1380	837	3171	1749	2127	7933	18071	742	667	3557	1909	4053	4616	10845	11254	7391	4600	7607
2048	5261	8616	7149	1663	1376	835	3164	1744	2121	7938	18021	729	655	3471	1901	4028	4598	10846	11261	7391	4560	7585
2049	5264	8593	7128	1658	1372	832	3158	1739	2115	7943	17972	707	635	3388	1892	4005	4582	10848	11268	7380	4342	7563
2050	5268	8580	7116	1655	1369	830	3154	1735	2111	7947	17942	687	617	3330	1885	3990	4573	10850	11275	7368	4136	7541
2051	5268	8554	7091	1649	1365	830	3147	1729	2104	7947	17883	683	613	3272	1882	3976	4563	10850	11204	7357	3923	7515
2052	5268	8536	7074	1645	1361	824	3142	1725	2099	7947	17844	682	612	3216	1880	3968	4559	10850	11133	7357	3908	7489
2053	5268	8499	7041	1638	1355	824	3130	1717	2089	7947	17764	679	610	3160	1875	3942	4541	10850	11062	7357	3880	7462
2054	5268	8479	7025	1634	1352	818	3123	1713	2084	7947	17723	678	609	3105	1873	3923	4528	10850	11062	7357	3866	7436
2055	5268	8459	7008	1630	1349	818	3116	1709	2079	7947	17682	677	608	3051	1870	3905	4514	10850	11062	7357	3852	7423

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
2023	1009	1009	1009	467	467	467	542	542	542	731	731	731	450	450	450	281	281	281
2024	922	927	894	409	423	406	513	505	487	659	668	643	394	407	391	265	261	252
2025	844	853	793	359	383	354	485	470	439	596	612	567	345	369	341	251	243	227
2026	774	786	703	314	348	308	459	438	395	539	560	500	302	334	296	237	226	204
2027	709	722	623	275	314	268	434	407	355	488	513	441	264	302	258	224	210	183
2028	687	664	552	265	285	233	422	379	319	473	469	388	255	273	224	218	196	164
2029	671	610	489	257	257	203	414	352	286	460	429	342	247	247	195	214	182	148
2030	648	561	433	249	233	176	399	328	257	445	393	302	240	224	169	206	169	133
2031	616	515	410	233	197	157	383	319	254	421	353	281	224	189	150	198	164	131
2032	585	470	389	217	160	137	368	310	252	398	313	261	208	154	131	190	160	130
2033	564	458	385	212	157	136	352	301	249	385	306	259	203	151	130	181	155	128
2034	552	450	382	208	155	135	344	295	247	377	301	257	200	149	130	177	152	127
2035	538	442	379	199	150	134	339	292	245	365	295	255	191	144	129	174	150	126
2036	527	436	377	193	147	133	334	289	244	357	290	253	185	141	128	172	149	125
2037	519	431	375	189	145	132	330	286	243	351	286	252	181	139	127	170	147	125
2038	512	427	374	186	143	132	326	284	242	346	283	251	178	137	126	168	146	124
2039	506	423	373	183	141	131	323	282	241	341	280	250	175	135	126	166	145	124
2040	502	421	372	181	140	131	321	281	241	338	278	249	173	134	125	165	144	124
2041	497	418	371	179	139	131	319	279	240	335	276	248	171	133	125	164	144	123
2042	494	416	370	177	138	130	317	278	239	332	274	248	169	132	125	163	143	123
2043	491	414	369	175	137	130	315	277	239	330	273	247	168	131	124	162	142	123
2044	488	412	368	174	136	130	314	276	238	328	272	246	167	130	124	161	142	122
2045	486	410	367	173	135	129	312	275	237	326	271	246	166	129	124	160	141	122
2046	484	409	366	172	135	129	311	274	237	325	270	245	165	129	124	160	141	122
2047	482	408	365	172	134	129	310	273	236	323	269	245	164	128	123	159	140	121
2048	480	406	365	171	134	129	309	273	236	322	268	244	163	128	123	159	140	121
2049	479	405	364	170	134	129	308	272	236	321	267	244	163	128	123	158	140	121
2050	477	405	364	170	133	129	308	271	235	320	267	244	162	127	123	158	139	121
2051	477	404	363	169	133	129	308	271	234	320	266	243	162	127	123	158	139	120
2052	474	402	362	169	133	128	305	269	233	318	265	243	162	127	123	157	138	120
2053	474	401	361	169	133	128	305	269	232	318	265	242	162	127	123	157	138	119
2054	472	399	358	168	132	128	304	267	230	317	263	241	161	126	123	156	137	118
2055	472	398	357	168	132	128	304	266	229	317	263	240	161	126	123	156	137	117

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
2023	592	592	592	441	441	441	151	151	151	519	519	519	431	431	431	88	88	88
2024	528	539	519	386	399	383	142	140	135	460	471	453	377	390	375	83	82	79
2025	472	491	455	338	361	333	135	130	122	408	428	396	330	353	325	78	76	71
2026	423	448	399	296	327	290	127	121	109	362	389	346	288	319	283	74	70	64
2027	379	408	350	258	295	252	120	113	98	322	354	303	252	288	246	70	65	57
2028	366	372	307	249	267	219	117	105	88	311	322	265	243	261	214	68	61	51
2029	355	339	269	241	242	190	114	97	79	301	292	231	235	236	186	66	57	46
2030	344	309	236	234	218	165	110	91	71	292	266	202	228	213	161	64	53	41
2031	324	272	217	219	184	147	106	88	70	274	231	184	213	180	143	61	51	41
2032	305	236	198	203	150	128	101	86	70	257	196	165	198	146	125	59	50	40
2033	296	230	196	198	147	127	97	83	69	250	192	164	193	144	124	56	48	40
2034	289	226	195	195	145	127	95	81	68	245	189	163	190	141	123	55	47	39
2035	279	221	193	186	141	125	93	80	68	235	184	161	181	137	122	54	47	39
2036	272	217	191	180	138	124	92	79	67	229	180	160	176	134	121	53	46	39
2037	267	214	190	176	135	124	91	79	67	224	177	159	172	132	120	53	46	39
2038	263	211	190	173	133	123	90	78	66	221	175	158	169	130	120	52	45	39
2039	259	209	189	171	132	123	89	78	66	217	173	158	166	128	119	51	45	38
2040	256	207	188	168	130	122	88	77	66	215	171	157	164	127	119	51	45	38
2041	254	206	187	166	129	122	87	77	66	212	170	156	162	126	118	51	44	38
2042	252	204	187	165	128	121	87	76	66	211	169	156	160	125	118	50	44	38
2043	250	203	186	163	127	121	86	76	65	209	168	156	159	124	118	50	44	38
2044	248	202	186	162	127	121	86	76	65	208	167	155	158	123	117	50	44	38
2045	247	201	185	161	126	120	86	75	65	206	166	155	157	122	117	50	44	38
2046	246	200	185	160	125	120	85	75	65	205	165	154	156	122	117	49	43	38
2047	245	200	185	160	125	120	85	75	65	204	165	154	155	121	117	49	43	37
2048	244	199	184	159	124	120	85	75	65	204	164	154	155	121	117	49	43	37
2049	243	199	184	158	124	120	84	74	65	203	164	154	154	121	116	49	43	37
2050	242	198	184	158	124	120	84	74	64	202	163	154	153	120	116	49	43	37
2051	242	198	184	157	124	119	84	74	64	202	163	153	153	120	116	49	43	37
2052	241	197	183	157	123	119	84	74	64	201	163	153	153	120	116	48	43	37
2053	241	197	183	157	123	119	84	74	64	201	162	153	153	120	116	48	43	37
2054	240	196	182	156	123	119	83	73	63	200	162	152	152	120	116	48	42	36
2055	240	196	182	156	123	119	83	73	63	200	162	152	152	120	116	48	42	36

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
2023	478	478	478	353	353	353	125	125	125	427	427	427	353	353	353	74	74	74
2024	427	435	419	309	319	307	118	116	112	378	388	373	309	319	307	70	69	66
2025	381	396	367	270	288	266	111	108	101	336	352	326	270	288	266	66	64	60
2026	341	361	322	236	261	231	105	100	90	298	320	285	236	261	231	62	59	53
2027	305	329	282	206	236	201	99	93	81	265	291	249	206	236	201	59	55	48
2028	295	300	247	199	213	174	96	87	73	255	264	217	199	213	174	57	51	43
2029	286	273	217	192	192	152	94	80	65	248	240	190	192	192	152	56	48	39
2030	277	249	190	186	174	132	91	75	59	240	218	166	186	174	132	54	44	35
2031	261	219	175	174	147	117	87	73	58	225	190	151	174	147	117	52	43	34
2032	245	190	159	162	119	102	84	70	57	211	161	136	162	119	102	49	42	34
2033	238	185	158	158	117	101	80	68	57	205	158	135	158	117	101	47	40	33
2034	233	182	157	155	115	101	78	67	56	201	155	134	155	115	101	46	40	33
2035	225	178	155	148	112	100	77	66	56	193	151	132	148	112	100	45	39	33
2036	219	175	154	143	109	99	76	65	55	188	148	131	143	109	99	45	39	33
2037	215	172	153	140	107	98	75	65	55	184	146	131	140	107	98	44	38	32
2038	211	170	152	138	106	98	74	64	55	181	144	130	138	106	98	44	38	32
2039	208	168	152	135	104	97	73	64	54	178	142	129	135	104	97	43	38	32
2040	206	166	151	133	103	97	72	63	54	176	141	129	133	103	97	43	37	32
2041	204	165	150	132	102	96	72	63	54	174	139	128	132	102	96	42	37	32
2042	202	164	150	130	101	96	71	63	54	173	138	128	130	101	96	42	37	32
2043	200	163	149	129	101	96	71	62	54	171	138	127	129	101	96	42	37	32
2044	199	162	149	128	100	96	71	62	54	170	137	127	128	100	96	42	37	32
2045	198	161	149	128	100	95	70	62	53	169	136	127	128	100	95	41	37	32
2046	197	161	148	127	99	95	70	62	53	168	136	127	127	99	95	41	36	31
2047	196	160	148	126	99	95	70	61	53	167	135	126	126	99	95	41	36	31
2048	195	160	148	126	98	95	69	61	53	167	135	126	126	98	95	41	36	31
2049	194	159	148	125	98	95	69	61	53	166	134	126	125	98	95	41	36	31
2050	194	159	147	125	98	95	69	61	53	166	134	126	125	98	95	41	36	31
2051	194	158	147	125	98	94	69	61	53	165	134	126	125	98	94	41	36	31
2052	193	158	147	124	98	94	69	60	52	165	133	125	124	98	94	40	36	31
2053	193	158	146	124	98	94	69	60	52	165	133	125	124	98	94	40	36	31
2054	192	157	146	124	97	94	68	60	52	164	133	125	124	97	94	40	35	31
2055	192	157	145	124	97	94	68	60	51	164	132	125	124	97	94	40	35	30

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

	$/kW							$/kWh						
	6hrs	8hrs	12hrs	24hrs	24hrs Tas	48hrs	48hrs Tas	6hrs	8hrs	12hrs	24hrs	24hrs Tas	48hrs	48hrs Tas
2023	3809	4139	4356	5808	3601	6818	3136	635	517	363	242	150	142	66
2024	3736	4060	4273	5697	3532	6688	3077	623	507	356	237	147	139	65
2025	3665	3983	4192	5589	3465	6561	3018	611	498	349	233	144	137	63
2026	3594	3905	4111	5481	3398	6434	2960	599	488	343	228	142	134	62
2027	3519	3825	4025	5367	3328	6300	2898	587	478	335	224	139	131	61
2028	3445	3744	3940	5254	3257	6167	2837	574	468	328	219	136	128	60
2029	3370	3663	3855	5140	3187	6034	2776	562	458	321	214	133	126	58
2030	3296	3582	3770	5026	3116	5901	2714	549	448	314	209	130	123	57
2031	3292	3577	3765	5020	3113	5893	2711	549	447	314	209	130	123	57
2032	3288	3573	3761	5014	3109	5886	2708	548	447	313	209	130	123	57
2033	3284	3569	3756	5008	3105	5879	2704	547	446	313	209	129	122	57
2034	3280	3565	3752	5002	3101	5872	2701	547	446	313	208	129	122	57
2035	3276	3561	3748	4997	3098	5866	2698	546	445	312	208	129	122	57
2036	3273	3556	3743	4991	3094	5859	2695	545	445	312	208	129	122	57
2037	3269	3552	3739	4985	3091	5852	2692	545	444	312	208	129	122	57
2038	3265	3548	3735	4979	3087	5845	2689	544	444	311	207	129	122	57
2039	3261	3544	3730	4974	3084	5839	2686	544	443	311	207	128	122	57
2040	3258	3540	3726	4968	3080	5832	2683	543	443	311	207	128	122	56
2041	3253	3535	3720	4960	3075	5823	2679	542	442	310	207	128	121	56
2042	3248	3529	3715	4953	3071	5814	2675	541	441	310	206	128	121	56
2043	3243	3524	3709	4945	3066	5805	2670	540	440	309	206	128	121	56
2044	3238	3519	3703	4938	3061	5796	2666	540	440	309	206	128	121	56
2045	3233	3513	3698	4930	3057	5788	2662	539	439	308	205	127	121	56
2046	3228	3508	3692	4923	3052	5779	2658	538	438	308	205	127	120	56
2047	3223	3503	3687	4915	3047	5770	2654	537	438	307	205	127	120	56
2048	3218	3497	3681	4908	3043	5761	2650	536	437	307	204	127	120	56
2049	3213	3492	3675	4900	3038	5752	2646	536	436	306	204	127	120	56
2050	3208	3487	3670	4893	3034	5744	2642	535	436	306	204	126	120	56
2051	3203	3481	3663	4884	3028	5734	2638	534	435	305	204	126	119	55
2052	3197	3475	3657	4876	3023	5724	2633	533	434	305	203	126	119	55
2053	3192	3469	3651	4868	3018	5714	2629	532	434	304	203	126	119	55
2054	3187	3463	3645	4859	3013	5705	2624	531	433	304	202	126	119	55
2055	3181	3457	3638	4851	3008	5695	2620	530	432	303	202	125	119	55

Apx Table B.8 Storage current cost data by source, total cost basis

	$/kWh								$/kW							
	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	Aurecon 2023-24	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO	Aurecon 2019-20	Aurecon 2020-21	Aurecon 2021-22	Aurecon 2022-23	Aurecon 2023-24	GenCost 2019-20	AEMO ISP Dec 2021	AEMO ISP Jun 2022/CSIRO
Battery (1hr)	1158	923	873	987	1009	-	-	-	1158	923	873	987	1009	-	-	-
Battery (2hrs)	729	618	580	713	731	-	-	-	1458	1236	1161	1427	1461	-	-	-
Battery (4hrs)	575	491	458	579	592	-	-	-	2301	1966	1833	2317	2367	-	-	-
Battery (8hrs)	522	434	402	515	519	-	-	-	4176	3468	3218	4116	4149	-	-	-
Battery (24hrs)	-	-	-	-	478	-	-	-	-	-	-	-	11472	-	-	-
Battery (48hrs)	-	-	-	-	427	-	-	-	-	-	-	-	20491	-	-	-
PHES (8hrs)	-	-	-	-	-	292	315	392	-	-	-	-	-	2336	2520	3135
A-CAES (12hrs)	-	-	-	371	-	-	-	-	-	-	-	4456	-	-	-	-
PHES (12hrs)	-	-	-	-	-	207	226	280	-	-	-	-	-	2482	2711	3365
A-CAES (24hrs)	-	-	-	-	294	-	-	-	-	-	-	-	7057	-	-	-
PHES (24hrs)	-	-	-	-	242	153	147	183	-	-	-	-	5808	3678	3537	4399
PHES (24hrs) Tasmania	-	-	-	-	-	-	91	114	-	-	-	-	-	-	2185	2727
PHES (48hrs)	-	-	-	-	142	86	111	138	-	-	-	-	6818	4121	5313	6608
PHES (48hrs) Tasmania	-	-	-	-	-	-	51	64	-	-	-	-	-	-	2468	3040

Notes: Batteries are large scale. Small scale batteries for home use with 2-hour duration are estimated at $1455/kWh or $2910/kW (Aurecon, 2024).

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
2023	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$/kW	$/GJ	
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	5079	13.5	89%	5079	19.5	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	2126	13.5	89%	2126	19.5	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1684	13.5	20%	1684	19.5	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	943	13.5	20%	943	19.5	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1908	13.5	20%	1908	19.5	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2134	40.9	20%	2134	43.2	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	11407	4.3	89%	11407	11.3	53%
Black coal	30	2.0	42%	53.2	4.2	0.0	5616	4.3	89%	5616	11.3	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	8236	0.6	89%	8671	0.7	53%
Nuclear SMR	30	4.4	33%	200	5.3	0.0	28581	1.1	89%	28581	1.3	53%
Nuclear large-scale	30	5.8	33%	200	5.3	0.0	8655	1.1	89%	8655	1.3	53%
Solar thermal	25	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%	17.0	0.0	0.0	1526	0.0	32%	1526	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	3038	0.0	48%	3038	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	5545	0.0	52%	5545	0.0	40%
2030												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	4070	7.7	89%	4024	13.8	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1747	7.7	89%	1731	13.8	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1443	7.7	20%	1432	13.8	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	865	7.7	20%	865	13.8	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1819	7.7	20%	1815	13.8	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2204	35.4	20%	2208	38.6	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	9751	2.7	89%	9675	4.1	53%
Black coal	30	2.0	42%	53.2	4.2	0.0	5141	2.7	89%	5168	4.1	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7494	0.7	89%	7441	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	15773	0.8	89%	15959	1.0	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	7813	0.8	89%	7928	1.0	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	6414	0.0	71%	7046	0.0	57%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	1166	0.0	32%	1173	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	2358	0.0	48%	2399	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	3720	0.0	54%	5230	0.0	40%

2040												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3209	7.6	89%	3831	15.2	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1702	7.6	89%	1702	15.2	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1408	7.6	20%	1408	15.2	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	850	7.6	20%	850	15.2	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1785	7.6	20%	1785	15.2	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2171	24.5	20%	2171	29.1	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8792	2.5	89%	9396	3.8	53%
Black coal	30	2.0	42%	53.2	4.2	0.0	5205	2.5	89%	5236	3.8	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7318	0.7	89%	7318	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	11219	0.5	89%	15337	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	7683	0.5	89%	7764	0.7	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	5020	0.0	71%	6134	0.0	57%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	832	0.0	32%	994	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1871	0.0	48%	1962	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2755	0.0	57%	4936	0.0	40%
2050												
Gas with CCS	25	1.5	44%	16.4	7.2	1.9	3146	7.6	89%	3590	15.2	53%
Gas combined cycle	25	1.5	51%	10.9	3.7	0.0	1655	7.6	89%	1655	15.2	53%
Gas open cycle (small)	25	1.5	36%	12.6	12.0	0.0	1369	7.6	20%	1369	15.2	20%
Gas open cycle (large)	25	1.3	33%	10.2	7.3	0.0	826	7.6	20%	826	15.2	20%
Gas reciprocating	25	1.1	41%	24.1	7.6	0.0	1735	7.6	20%	1735	15.2	20%
Hydrogen reciprocating	25	1.0	32%	33.0	0.0	0.0	2111	17.8	20%	2111	22.7	20%
Black coal with CCS	30	2.0	30%	77.8	8.0	4.1	8575	2.5	89%	9011	3.8	53%
Black coal	30	2.0	42%	53.2	4.2	0.0	5149	2.5	89%	5268	3.8	53%
Brown coal	30	4.0	32%	69.0	5.3	0.0	7116	0.7	89%	7116	0.7	53%
Nuclear SMR	30	4.4	33%	200.0	5.3	0.0	11275	0.5	89%	14478	0.7	53%
Nuclear large-scale	30	5.8	33%	200.0	5.3	0.0	7462	0.5	89%	7541	0.7	53%
Solar thermal	25	1.8	100%	124.2	0.0	0.0	4045	0.0	71%	5154	0.0	57%
Large scale solar PV	30	0.5	100%	17.0	0.0	0.0	583	0.0	32%	791	0.0	19%
Wind onshore	25	1.0	100%	25.0	0.0	0.0	1763	0.0	48%	1924	0.0	29%
Wind offshore (fixed)	25	3.0	100%	149.9	0.0	0.0	2691	0.0	61%	4778	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 discount rate for all technologies is 5.99%.

Apx Table B.10 Electricity generation technology LCOE projections data, 2023-24 $/MWh

Category	Assumption	Technology	2023		2030		2040		2050	
			Low	High	Low	High	Low	High	Low	High
Peaking 20% load		Gas open cycle (small)	236	296	167	228	164	240	162	238
		Gas open cycle (large)	204	269	138	204	136	219	135	217
		Gas reciprocating	231	284	176	230	173	240	171	238
		H_2 reciprocating	580	606	521	557	397	449	319	374
Flexible load, high emission		Black coal	107	211	88	141	87	140	86	140
		Brown coal	118	199	110	175	108	173	106	169
		Gas	124	183	79	136	78	145	77	144
Flexible load, low emission		Black coal with CCS	193	364	156	248	144	239	142	232
		Gas with CCS	177	266	119	200	109	208	108	203
		Nuclear SMR	387	641	230	382	171	366	172	349
		Nuclear large-scale	155	252	141	233	136	226	133	221
		Solar thermal	134	168	109	148	89	132	76	115
Variable	Standalone	Solar photovoltaic	47	79	37	63	28	55	22	46
		Wind onshore	66	109	52	88	43	74	41	73
		Wind offshore (fixed)	146	190	105	182	81	174	75	170
Variable with integration costs	Wind & solar PV combined	60% VRE share	99	139	73	109				
		70% VRE share	97	138	78	113				
		80% VRE share	98	139	83	120				
		90% VRE share	100	143	89	128				

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
2023	1919	3141	1919	3141	1919	3141
2024	1575	2577	1552	2540	1622	2655
2025	1318	2339	1280	2248	1399	2394
2026	1118	2124	1071	1990	1223	2159
2027	955	1923	902	1757	1076	1942
2028	902	1741	765	1550	955	1746
2029	855	1576	654	1368	853	1570
2030	773	1427	562	1208	766	1412
2031	734	1292	530	1066	714	1270
2032	705	1170	499	941	682	1142
2033	680	1059	479	831	644	1027
2034	657	959	456	734	612	924
2035	636	868	434	648	580	831
2036	618	786	415	572	564	747
2037	601	712	397	505	548	672
2038	584	645	381	446	534	605
2039	565	584	363	393	516	544
2040	529	529	347	347	489	489
2041	516	516	332	332	478	478
2042	499	499	319	319	462	462
2043	487	487	306	306	446	446
2044	468	468	295	295	429	429
2045	450	450	285	285	415	415
2046	430	430	275	275	403	403
2047	422	422	267	267	393	393
2048	415	415	257	257	384	384
2049	398	398	245	245	375	375
2050	377	377	229	229	362	362
2051	377	377	229	229	362	362
2052	376	376	225	225	361	361
2053	376	376	225	225	361	361
2054	375	375	221	221	360	360
2055	375	375	221	221	360	360

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 (%)	References
Photovoltaics	Current policies	G	30	13	(IEA 2021, IRENA, 2022, Fraunhofer ISE, 2015)
		L	-	17	
Photovoltaics	Global NZE by 2050	G	30	23	
		L	-	17	
Photovoltaics	Global NZE post 2050	G	30	23	
		L	-	17	
Electrolysis	Current policies	G	10	5	(Schmidt et al., 2017)
		L	10	5	
Electrolysis	Global NZE by 2050	G	20	9	
		L	20	9	
Electrolysis	Global NZE post 2050	G	10	5	
		L	10	5	
Ocean	Current policies	G	5	5	(IEA, 2021)
	Global NZE by 2050	G	20	10	

	Global NZE post 2050	G	14	7	
Fixed offshore wind	Current policies	G	5	5	(Samadi, 2018; Zwaan, et al. 2021; Voormolen et al. 2016; IEA, 2021)
Fixed offshore wind	Global NZE by 2050	G	20	10	
Fixed offshore wind	Global NZE post 2050	G	8	8	
Floating offshore wind	Current policies	G	10	5	
		G	10	5	
Floating offshore wind	Global NZE by 2050	G	20	10	
		G	20	10	
Floating offshore wind	Global NZE post 2050	G	15	7.5	
		G	15	7.5	
Utility scale energy storage – Li-ion	Current policies	G	-	7.5	(Grübler et al., 1999; McDonald and Schrattenholzer, 2001)
		L	-	7.5	
Utility scale energy storage – Li-ion	Global NZE post 2050	G	-	10	
		L	-	10	
Utility scale energy storage – Li-ion	Global NZE by 2050	G	-	15	
		L	-	15	

Solar photovoltaics is listed as one technology with global and local components however there are two separate PV plant technologies in GALLME. Rooftop PV includes solar photovoltaic modules, and the local learning component is the balance of plant (BOP). Large scale PV also include modules and BOP. However, a discount of 25% is given to the BOP to take into account economies of scale in building a large scale versus rooftop PV plant. Inverters are not given a learning rate instead they are given a constant cost reduction, which is based on historical data.

The potential for local learning means that technology costs are different in different regions in the same time period. This has been of particular note for technology costs in China, which can be substantially lower than other regions. GALLME uses inputs from Aurecon (2024) 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 (%)	References
Coal, supercritical	-	-	-	
Coal, ultra-supercritical	G	-	2	(IEA, 2008; Neij, 2008)
Coal/Gas/Biomass with CCS	G	20	10	(EPRI 2010; Rubin et al., 2007)
	L	20	10	As above + (Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Gas peaking plant	-	-	-	
Gas combined cycle	-	-	-	
Nuclear	G	-	-	(IEA, 2008)
Nuclear SMR	G	20	10	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Diesel/oil-based generation	-	-	-	
Reciprocating engines	-	-	-	
Hydro and pumped hydro	-	-	-	
Biomass	G	-	5	(IEA, 2008; Neij, 2008)
Concentrating solar thermal (CST)	G	14.6	7	(Hayward & Graham, 2013)
Onshore wind	G	-	4.3	(IEA, 2021; Hayward & Graham, 2013)
	L	-	9.8	As above
CHP	-	-	-	
Conventional geothermal	G	-	8	(Hayward & Graham, 2013)
	L	20	20	(Grübler et al., 1999; Hayward & Graham, 2013; McDonald and Schrattenholzer, 2001)
Fuel cells	G	-	20	(Neij, 2008; Schoots, Kramer, & van der Zwaan, 2010)
Steam methane reforming with CCS	G	20	10	(EPRI, 2010; Rubin et al., 2007)
	L	20	10	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.

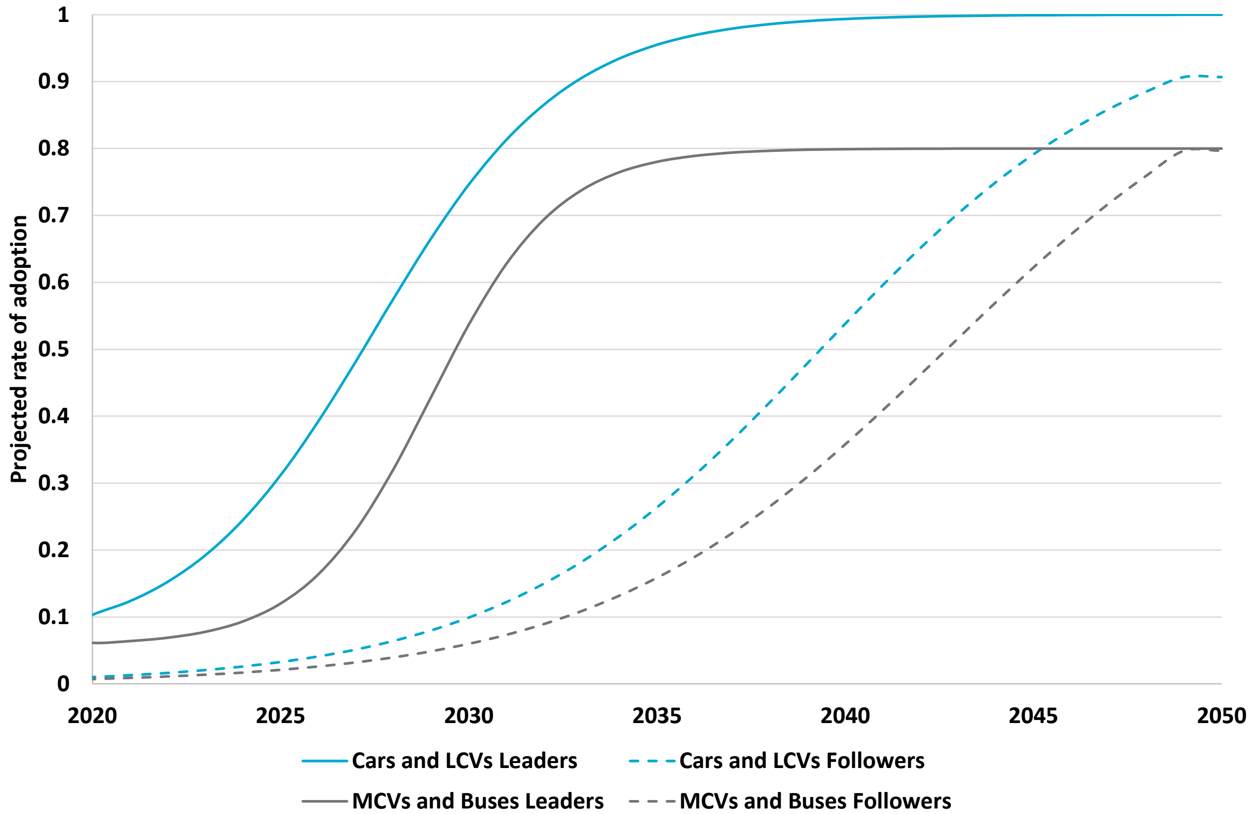
In addition to the offshore wind learning rate, we have included an exogenous increase in the capacity factor up to the year 2050 of 6% in lower resource regions, and 7% in higher resource regions, up to a maximum of 55%, in capacity factor. This assumption extrapolates past global trends (see Appendix 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

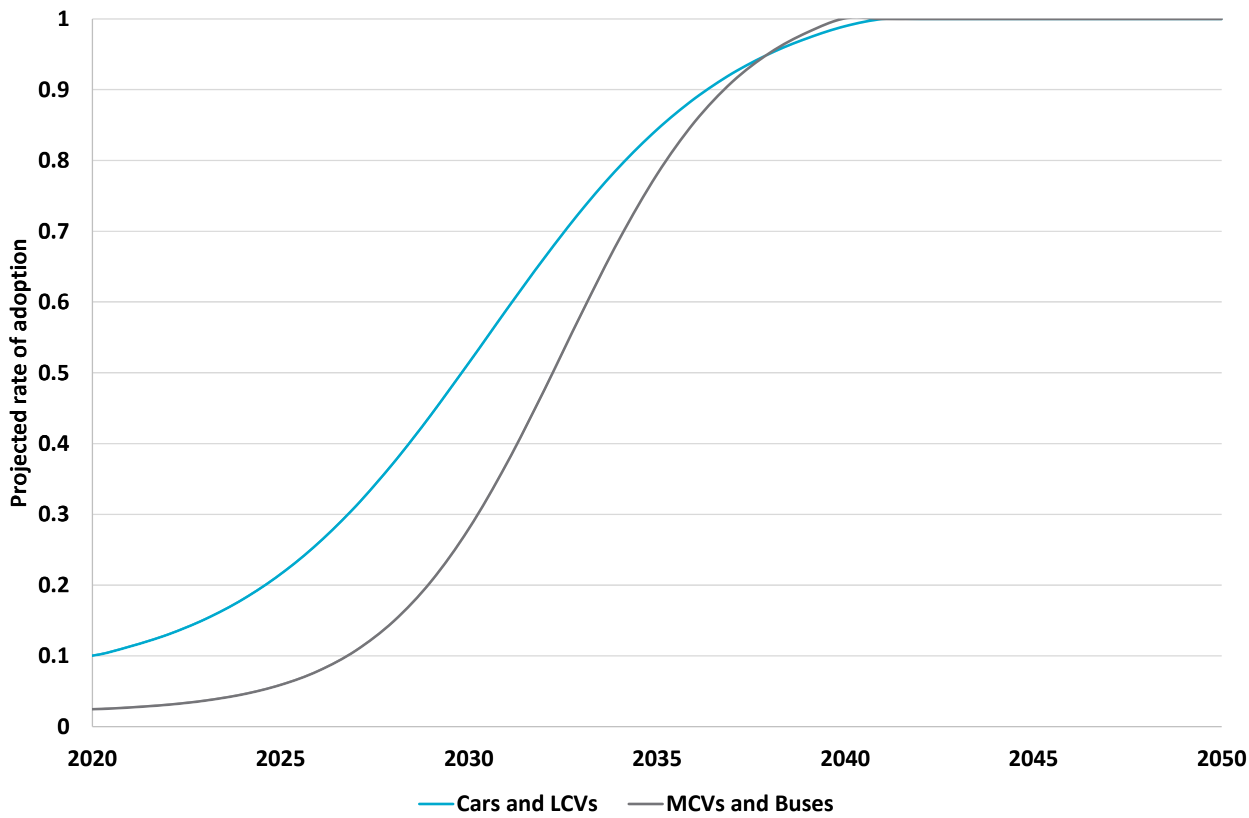
Various elements of underlying electricity demand are sourced from the World Energy Outlook (IEA, 2021; IEA 2022; IEA 2023). Demand data is provided for the Announced Pledges scenario, which is used in our *Global NZE post 2050* scenario. The demand data from the Stated Policies (STEPS) scenario is used 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

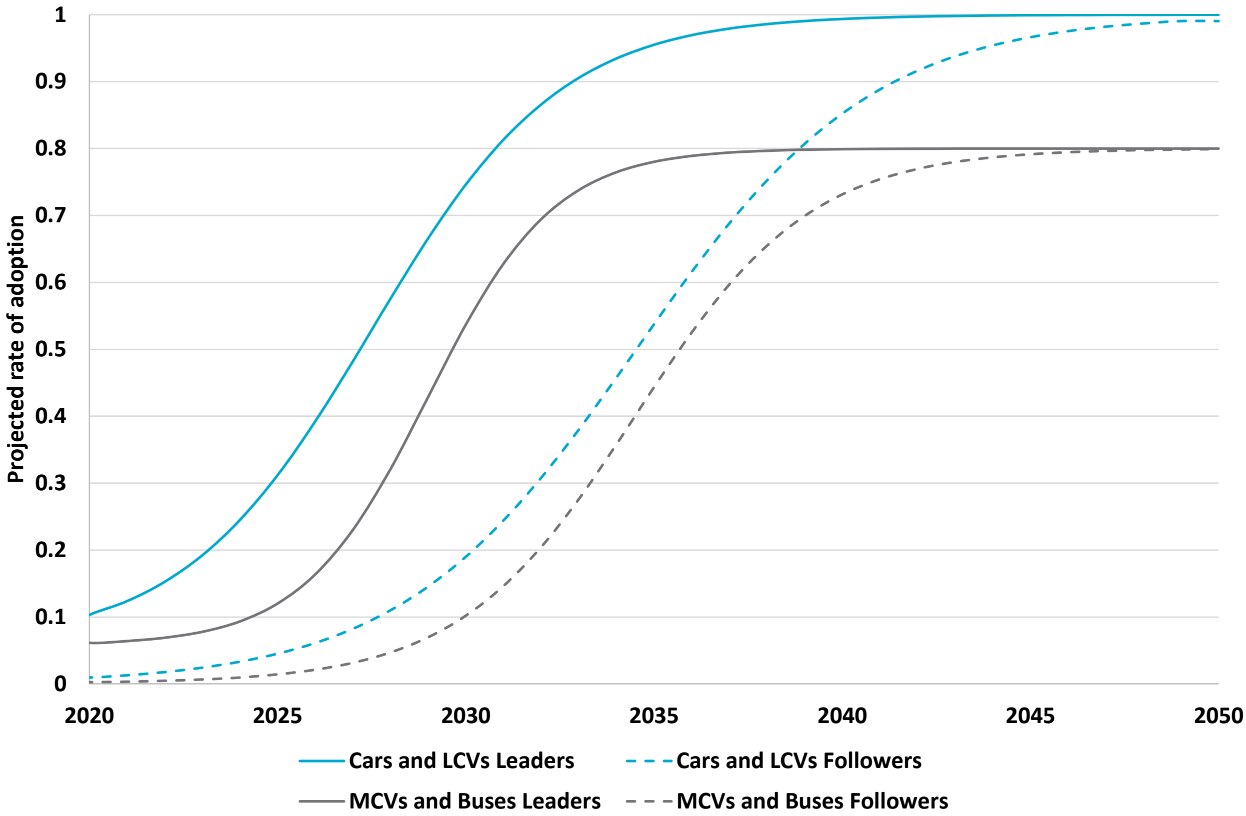
Global adoption of electric vehicles (EVs) by scenario is projected using an adoption curve calibrated to a different shape to correspond to the matching IEA World Energy Outlook scenario sales shares to ensure consistency in electricity demand. The rate of adoption is highest in the *Global NZE by 2050* scenario, medium in the *Global NZE post 2050* scenario and low in the *Current policies* scenario consistent with climate policy ambitions. The shape of the adoption curve varies by vehicle type and by region, where countries that have significant EV uptake already, such as China, Western Europe, India, Japan, North America and rest of OECD Pacific, are leaders and the remaining regions are followers. Cars and light commercial vehicles (LCV) have faster rates of adoption, followed by medium commercial vehicles (MCV) and buses. The EV adoption curves for the *Current policies*, *Global NZE by 2050* and *Global NZE post 2050* scenarios are shown in Apx. Figure C.1, C.2 and C.3 respectively. There is no difference between EV sales shares for Followers and Leaders in the *Global NZE by 2050* scenario. The adoption rate is applied to new vehicle sales shares.



Apx Figure C.1 Projected EV sales share under the *Current policies* scenario



Apx Figure C.2 Projected EV adoption curve (vehicle sales share) under the *Global NZE by 2050* scenario



Apx Figure C.3 Projected EV sales share under the *Global NZE post 2050* scenario

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	117
Global NZE post 2050	251
Global NZE by 2050	428

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 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 & Graham, 2017 for more information on sources). With the exception of rooftop 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[48]. 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
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 (Aurecon, 2024)(Aurecon, 2023a) (Aurecon, 2022) (Aurecon, 2021) (IEA, 2016b) (IEA, 2015), capacity factors from (IRENA, 2022) (IEA, 2015) (CO2CRC, 2015) and historical technology installed capacities from (IEA , 2008) (Gas Turbine World, 2009) (Gas Turbine

[48] 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.

World, 2010) (Gas Turbine World, 2011) (Gas Turbine World, 2012) (Gas Turbine World, 2013) (UN, 2015a) (UN, 2015b) (US Energy Information Administration, 2017a) (US Energy Information Administration, 2017b) (GWEC) (IEA, 2016a) (World Nuclear Association, 2017) (Schmidt, Hawkes, Gambhir, & Staffell, 2017) (Cavanagh, et al., 2015).

Appendix D Frequently asked questions

The following list of questions represent 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. 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 its 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 the that future evolution of major drivers of the global energy system will not be smooth, particularly considering the recent pandemic and Ukraine war experiences. 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 judgement 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 Why did you use the capital cost of a single failed project in the United States for your representative nuclear SMR cost (the UAMPS Carbon Free Power Project)?

While there are several currently existing and proposed SMR projects, only the UAMPS project has been willing to provide an open and reliable costing for their project. Costings for projects not built often turn out to be optimistic or marketing pieces and for those reasons are not considered reliable. The UAMPS project is deemed to be reliable because the developers were prepared to financially commit and there would have been financial consequences if they had provided lower than achievable estimates and then tried to proceed at a higher cost. Their subscription model for power produced meant they had to agree to a cost up front. If they underestimated costs, they would be liable for the shortfall. In contrast, there are no financial consequences for manufacturers who supply unrealistically low estimates for technologies they are not committed to build and sell the power from themselves. While many submissions requested GenCost use different data, no evidence was provided for an alternative real project to the UAMPS project. All other suggested costs were vendor estimates for projects the vendor has not committed to directly build or own.

D.3.2 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 policy has provided international partnership support and direct grants for critical minerals projects[49].

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

D.3.3 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, the length depending on the scenario.

The data on technology project costs from Aurecon 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 Aurecon (2024) 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.

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

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.

D.3.4 Why is the uncertainty in the data not emphasised more?

Aurecon (2024) 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. Aurecon (2024) also provide factors to convert the general costs to specific locations in the National Electricity Market. Nevertheless, the capital cost projections provided in GenCost are in relation to the general cost of capital rather than specific locations. Therefore, this level of uncertainty will always be a feature of GenCost capital cost data.

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

Some stakeholders take a view that although Australia has bipartisan commitment for net zero emissions by 2050, the highest greenhouse gas emitting options should remain on the table. The deployment of new coal has low plausibility given its high emission intensity. A high efficiency design brings it closer to being plausible. 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 important to start from a reasonably 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 queried why this was 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 a refurbishment) 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 for that technology. The economic life is an input provided by the engineering firm that AEMO commissions each year as 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.

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 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 the Aurecon (2024) 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 are tested over a shorter period than would occur in reality. It is not clear how well deployed storage projects will match the lab tests. Their operation may be more prone to partial discharge 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 it will be less damaging to the 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). This capacity factor is also common when examined over some multi-decade data sources (Clarke and Graham, 2022). The simple reason for this outcome is because most baseload plant 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 typically brown coal plant which have a significant 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 up to 89% based on the maximum achieved by black coal generators. At the low end of the range a capacity factor of 53% is assumed for new black coal or nuclear generators which is equivalent to achieving 10% below the average capacity factor for black coal. New coal or nuclear would be competing against existing coal plant which have lower marginal costs given their capital costs may already have been paid back and they may have more competitive existing coal supply contracts. In this context, new coal or nuclear generators are expected to struggle to present the lowest cost bids to the dispatch market.

Many would also point out that the higher penetration of renewables, which have a zero fuel cost, will also make it difficult for new baseload plant to achieve high capacity factors. That may be true in the longer run as renewables increase their market share. However, the approach to capacity factors in GenCost does not rely on that future development in setting capacity factor ranges. Rather the approach recognises that the main challenge for new baseload generators for the next decade, as it has been in the past, is the more competitive bids of existing baseload generators.

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. 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 avoid such projects in preference for more attractive investment options. As such 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 none of the topics presented in the feedback have a large enough impact on LCOE to warrant a change in the boundary or formula (and no quantitative evidence of their significance was provided). That is, it would add complexity and cost to the project without significantly changing the outcome of the comparisons.

One exception is 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 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. 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?

Aurecon's report and spreadsheet breaks down the capital cost into three components: equipment, land and development and installation costs. Development costs are captured in the land and development segment. Aurecon (2024) 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*
- *Project administration, grid connection studies, and agreements*
- *Permits and licences, approvals (development, environmental, etc)*
- *Land procurement and applications*

The costs for project and land procurement are highly variable and project specific. For the purposes of this report, and outlining development and land costs for a general project within each technology category, a simplified approach must be taken. Land and development costs are calculated as a percentage of capital equipment, and as a result, absolute values associated with these costs will change for those technologies whose equipment capital costs have changed. These costs do not include any applicable fees, such as fees paid to councils, local authorities, electrical connection fee etc. An indicative estimate has been determined based on a percentage of CAPEX estimate for each technology from recent projects, and experience with development processes.".

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[50]. 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 do other studies find higher costs than GenCost for integrating variable renewables in the electricity system?

Stakeholders have forwarded research which they believe arrives at a different result to GenCost on the cost of integrating renewables and requested that GenCost adopt their methodology or justify why GenCost arrives at different results. In reviewing these studies, which in some cases appear in peer reviewed journals, it became evident that there were several common limiting factors which explain why they find higher variable renewable integration costs. These include:

- Requiring that the variable renewable share be 100% (there is no such requirement in Australia and such an approach would require the non-sensical step of shutting down existing non-variable renewable generation such as the existing Snowy hydro scheme and biomass generation)
- Limiting the types of storage technologies available to the system (e.g. only allowing batteries to participate rather than all storage options)
- Limiting the duration of storage technologies available to the system (e.g. only including one possible storage duration)
- Limiting access of the system to realistically diverse renewable profiles (e.g. using just one profile for solar and one for wind)
- Imposing inertia and system security constraints but only allowing a limited range of technologies to supply these services
- Ignoring the availability of existing generation capacity in the system.

To be clear, none of the studies reviewed included all of these limiting factors but they all included at least one. The following table matches the common limiting factors to the published work. The table focuses on Idel (2022) because it was forwarded by more than one stakeholder and on Cross et al. (2023) of Blueprint Institute because it is the most recent example specific to Australia.

[50] 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

Apx Table D.1 Comparison of limiting factors applied in academic literature to the calculation of variable renewable integration costs and the GenCost approach

Limiting factor	Idel (2022)	Cross et al. (2023) of Blueprint Institute	GenCost
Requiring 100% variable renewable share	The main analysis upon which conclusions are based assumes 100% VRE. A 95% VRE sensitivity that was included results in very different outcomes.	Focus on 90% and 99% calculated on the basis of VRE plus existing renewable share combined (VRE share not separately provided)	Considers 60%, 70%, 80% and 90% VRE shares
Limiting storage technologies	Only batteries are included	Only batteries are included	Lithium batteries, flow batteries, compressed air and pumped hydro storage included
Limiting the duration of storage technologies	Only 3 hour batteries are allowed	Only 4 hour batteries are allowed	lithium-ion batteries at 1, 2, 4, or 8 hours; flow batteries at 4, 8, 12 or 24; compressed air at 8, 12, 24 or 48; and pumped hydro at 6, 8 12, 24 or 48 hours. The 168 hour Snowy 2.0 pumped hydro project is also included
Limiting diversity of renewable profiles	Single profile each for solar and wind	Single profile for solar and wind per state	Profiles for wide range of Australian Renewable Energy Zones included
Limiting technologies that can meet system security requirements	NA	Synchronous generators only, but pumped hydro excluded	Synchronous condensers, grid forming batteries and synchronous generators all available to be deployed

It is our expectation that were these limiting factors not imposed, the results of their analysis of the cost of integrating variable renewables would be lower and likely similar to GenCost. For example, when Idel (2022) removes the requirement for a 100% variable renewable share, decreasing it to 95%, system cost estimates halve in the German and Texas case studies. In the case of Texas, the cost was $97/MWh which is inside the range of costs estimated by GenCost despite the higher VRE share and limits on storage technologies.

Gilmore et al (2023) published research which provided an estimate of the impact on the cost of electricity from a high VRE system of only including batteries in the storage options. They found a battery only scenario increased costs by 35% compared to a system that also allowed pumped hydro storage. Gilmore et al (2023) also finds costs within the range estimated by GenCost.

One stakeholder submission argued that it is necessary to assume that renewables can provide baseload power sources like coal and gas. To be clear, GenCost is not targeting the production of baseload[51] power as the point of comparison. Electricity system demand is not flat. The cost of integrated VRE presented in GenCost are for delivery of reliable power to meet system load. However, CSIRO acknowledges that there will be circumstances where flat or baseload power is required such as in direct contracts to grid connected industrial facilities such as Aluminium smelters or in the industrial off-grid sector (e.g. mining). In these circumstances, it is likely that VRE will be more costly than it is when undertaking the task of supplying general residential and commercial customer demand. There is published research available on this topic based on CSIRO modelling (ClimateWorks and ClimateKic, 2023). The challenge and opportunity for Australia's industrial sector is whether it can access low emission industrial electricity supply at lower costs than our international competitors. This will depend not just on the generation technologies selected but on other factors such as relative labour and installation costs (Graham and Havas, 2023).

D.4.8 Why are integration costs not increasing with VRE share in 2023 but increase in the 2030 results?

Stakeholders requested that all of the currently committed transmission and storage projects in Australia be included in any assessment of current VRE integration costs. This request arises from some stakeholder views that the costs of integrating VRE may be high and none of the costs already committed should be left out when undertaking the assessment, regardless of the VRE share being targeted.

However, not all of those committed transmission and storage projects are strictly necessary to reach lower VRE shares at current demand. They are being built in anticipation of high renewable electricity supply and system demand. Consequently, the integration costs from these projects are high at low VRE shares because the investment is more than is strictly necessary for a moderate increase in VRE share to meet 2023 demand. However, as we increase the VRE share these new investments are better utilised, decreasing the calculated costs of integration.

The same problem does not arise in 2030 because, following the same methodology we apply in 2023, existing capacity is not included in the LCOE, only committed projects and anything additional needed (as assessed by the modelling framework). Without the forced inclusion of a block of committed project expenditure that is necessary in the 2023 calculation, the 2030 result conforms to expectations of higher integration costs as the VRE share increases.

In reality, the calculated 2023 VRE LCOE costs with integration will not be experienced by the electricity sector. Variable renewable generation will be deployed progressively (rather than in a single year) and likely at lower costs as cost reductions resume following recovery from recent

[51] It is also worth noting that baseload generation which is taken to mean almost constant production except for periods of maintenance by this stakeholder, is something that happens at a very small minority of plants in Australia with the average historical capacity factor of coal plants being around 60%.

global inflationary pressures. Electricity demand is expected to increase given the key role of electrification in decarbonising Australia's economy and this increase in volume will increase the volume of renewable generation to improve the utilisation of the planned integration assets. In this sense, the 2023 LCOE results could be considered an upper bound if variable renewable technology cost reductions never occur again and electricity demand is flat.

LCOE is not a tool that is designed to capture transitional costs. LCOE places all costs in a single year. Stakeholders that wish to explore system costs over multiple time periods will need to review existing multi-year modelling studies or commission new modelling that uses a multi-year framework. The information GenCost publishes on capital costs over time is targeted at providing the information needed for others to conduct multi-year modelling studies. It is not designed to provide those studies directly. LCOE data published by GenCost provides an indication of what those deeper modelling studies might find regarding technology competitiveness.

D.4.9 Why do other studies show the cost of storage increasing more rapidly with higher VRE share?

If storage is provided to an electricity system as the only technology available for variable renewables to meet electricity demand reliably, then the cost of storage increases exponentially as the VRE share increases. However, this is not a least cost system for integrating variable renewables. A least cost system uses a combination of storage of varying durations, peaking plant (based on either natural gas, renewable gas or hydrogen or hydro if it is available) and transmission (to source diverse renewables that complement each other). In particular, peaking plant is a more cost effective means to provide generation in so-called 'renewable droughts'. When peaking pant are made available to an electricity system with increasing VRE share, the power ratio of storage to renewable capacity tends to plateau at the 80-90% VRE share rather than continue to increase (as is otherwise found in studies where peaking plant are not made available). Transmission and spilling electricity also reduce the need for more storage. Modelling studies that find an exponential increase in storage costs as the VRE share increases have artificially constrained the options available to support variable renewables.

D.4.10 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.4.11 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.

D.4.12 Why do you apply only one discount rate or weighted average cost of capital to all technologies?

This question arises in the context of stakeholder concerns that some projects might be government funded and receive a lower financing rate 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. We broadly align our discount rates with those used by the Australian Energy Market Operator who provide detailed reasons for their choices including a stakeholder consultation process.

D.4.13 Why did you take the maximum and average of existing generator prices to create the high and low range greenfield 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 (greenfield) projects which are different to coal prices that are received by existing projects. 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 greenfield and existing coal generators. Reflecting the issues discussed above, average greenfield 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 greenfield coal prices.

After June 2022, AEMO has no longer published greenfield 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 greenfield coal prices, GenCost 2023-24 had to apply a new methodology based on the only available data which was coal prices for existing generators. Knowing that greenfield coal prices are at least as high as that for existing generators, for the maximum, GenCost 2023-24 simply takes the maximum of existing generator prices.

However, for the minimum greenfield 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 greenfield 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.4.14 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.4.15 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 will not go ahead if their capacity factor is too low. 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.4.16 Why use historical 2023 coal and gas prices that are impacted by the Ukraine War for 2023 LCOE estimates instead of a longer time series?

GenCost uses a simple LCOE formula that is highly transparent but as a result is not comprehensive. The formula only accepts one fuel price for each selected high and low range calculation rather than a time series and we have applied this approach consistently since inception in 2018. The concern about using a single price has only arisen now because coal and gas prices have gone through a high price event owing to the impact of the Ukraine war on global and local fossil fuel prices. To accept a time series the LCOE calculation approach would need to change to a cash flow analysis. GenCost would prefer to avoid a cash flow approach to maintain the current level of transparency and simplicity.

The question of whether the use of prices from an unstable point in time is fair depends on the purpose and context. If GenCost only provided a 2023 LCOE and no other year and only used a single fuel price, there is no doubt the use of 2023 fossil fuel prices would be misleading in terms of showing the potential range of costs. However, the high fossil fuel price is only used to populate the high range LCOE estimate in 2023. A low fossil fuel price is used to also calculate a low range LCOE estimate. Furthermore, updates on the LCOE range are also provided for 2030, 2040 and 2050 which capture the change in fuel prices after 2023.

The inclusion of the high fossil fuel prices from 2023 also serves to highlight the risks of Australia deploying new fossil fuel assets. While the Ukraine war impacts on fossil fuel prices has moderated (partly due to government intervention in the form of price caps), Australia remains exposed to future international fossil fuel price volatility which could be driven by other new global events. The experience of the Ukraine war is that such events have a very high impact on the Australian electricity system and so should not be ignored.

D.4.17 Why does GenCost only conduct LCOE analysis instead of system cost to society analysis?

Some stakeholders believe GenCost is obligated to provide a system cost to society analysis. The stated purpose of GenCost is to provide essential capital cost information for the modelling community to use in their own studies. GenCost also provides LCOE data for the non-modelling community that can provide an indication of the relative cost competitiveness of different technologies.

CSIRO has significant experience in conducting whole of electricity system studies[52] and can therefore say with confidence that such a study would increase the annual budget of GenCost by around five- to ten-fold. It is therefore not a simple extension. Substantially expanding the scope of GenCost or creating a new separate project to accommodate stakeholder interest in whole of system studies is not planned at present. However, CSIRO does operate in this field and new separate research of this type is likely to be available in the future.

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[52] See for example these projects: https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/ and https://www.transgrid.com.au/about-us/network/network-planning/energy-vision.

D.4.18 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.

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. While additional renewable supply has, in some regions, lowered wholesale electricity prices, customers may not immediately feel the impact due to existing higher priced supply contracts. There is no guarantee that renewables or any other new entrant technology will maintain downward pressure on prices. If 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.

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 signficance

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

E.4 Input data quality level is reasonable

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

A. Domestically observable projects (this might be through public data or data held by engineering and construction firms)
B. Extrapolations of domestic or global projects (e.g., observed 2-hour battery re-costed to a 4-hour battery, gas reciprocating engine extrapolated to a hydrogen reciprocating engine)

C. Globally observable projects

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

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

While paper studies are least preferred and would normally be rejected, 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, they cannot be validated by stakeholders. However, confidential sources could provide some guidance to 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 is similar.

Shortened forms

Abbreviation	Meaning
A-CAES	Adiabatic Compressed Air Energy Storage
ABS	Australian Bureau of Statistics
AE	Alkaline electrolysis
AEMO	Australian Energy Market Operator
APGT	Australian Power Generation Technology
BAU	Business as usual
BOP	Balance of plant
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CST	Concentrated solar thermal
ESOO	Electricity Statement of Opportunities
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
IEA	International Energy Agency
ISP	Integrated System plan

Abbreviation	Meaning
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelised Cost of Electricity
LCOS	Levelised cost of storage
LCV	Light commercial vehicle
MCV	Medium commercial vehicle
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
PASA	Projected Assessment of System Adequacy
PEM	Proton-exchange membrane
pf	Pulverised fuel
PHES	Pumped hydro energy storage
PV	Photovoltaic
REZ	Renewable Energy Zone
RO	Reliability Obligation
SDS	Sustainable Development Scenario
SMR	Small modular reactor
STEPS	Stated Policies Scenario

Abbreviation	Meaning
SWIS	South-West Interconnected System
TWh	Terawatt hour
USC	Ultra-supercritical
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEO	World Energy Outlook

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