Appendix D Frequently asked questions

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

D.1 Process

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

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

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

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

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

D.2 Scenarios

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

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

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

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

The GenCost 2023-24 final report provides a detailed discussion of the history of estimating nuclear SMR costs in Section 2.4

D.3.3 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 both build and sell the power from themselves. While many submissions have in the past requested GenCost use different data, no evidence was provided for an alternative project with data quality equal to or better than the UAMPS project. All other suggested costs were vendor estimates for projects the vendor has not committed to directly build or own which we regard as low quality data.

D.3.4 Do you assume Australia continues to rely on overseas technology suppliers or are you assuming Australia develops its own original equipment manufacturing capability?

The context of this question is the concern that reliance on overseas manufacturers makes Australia vulnerable to non-competitive market pricing (e.g. the dominance of China), delayed access to technology because of competing buyers or represents a security of supply risk in the event of conflict in or with supplying countries. In this context, some government policies have provided international partnership support and direct grants for critical minerals projects[41].

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

D.3.5 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

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

significant structural break. Based on the evidence available of similar events, the approach taken has been to assume a reasonably quicker resolution of high technology prices with some lingering effects for 3 to 6 years, the length depending on the scenario.

The data on technology project costs from 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 (2024b) points to cost pressures easing. Commodity price reporting also indicates cost pressures have eased in raw material markets such as lithium.

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

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

D.3.6 Why is the uncertainty in the data not emphasised more?

Aurecon (2024b) 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 (2024b) also provide factors to convert the general costs to specific locations in the National Electricity Market. In that context GenCost data is based on transporting and installing equipment not more than 200km from Melbourne but can be converted to other locations. An important aspect for GenCost is that all data is on a common basis.

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

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

D.3.7 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 even more important to start from a high efficiency coal generation technology.

D.4 LCOE

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

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

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

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

Determining the economic life of storage is more complex because the cycle life comes into play in determining the life of some components. The cycle life and intended use of the storage device might also be something debt and equity providers are also interested in to set the repayment date. Batteries in GenCost are costed for a project which has purchased a 20-year warranty on the battery (this warranty is costed as part of the ongoing operating and maintenance cost – see Aurecon (2024b) for more information on this).

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

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

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

In the last ten years in Australia, baseload generators have had an average capacity factor of 59% (see Appendix D GenCost 2022-23 final report). The simple reason for this outcome is that most baseload plants need to reduce production at night and in milder seasons when demand is lowest. There are individual generators that do achieve around 90%. These are typically brown coal plants 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 of 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. Around 10% of nuclear generators globally run at less than 60% capacity factor and have run at over 90%. However, we prefer to use Australian data for the plausible baseload plant operation data because it is consistent with our electricity load curve while other countries may have very different loads. For example, some equatorial and northern regions with hotter and colder climates have higher rates of air conditioning in buildings leading to flatter electricity loads (where either electricity or combined heat and power are the energy source).

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

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

For all existing technologies there are some generators that are performing poorly relative to what might be expected, and these represent the low range of historical capacity factors which were examined in Appendix D of the GenCost 2022-23. 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. Accordingly, we apply a common rule across renewables, coal, nuclear and gas that the minimum capacity factor for new plant is 10% below the previous ten years average capacity factor for that technology or its nearest equivalent grouping (baseload technologies are treated as one group).

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

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

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

Adding these additional parameters would greatly expand the physical and time boundary of the generic generation projects assumed in GenCost and require more complicated formulas to implement. Our current understanding is that 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 those captured in the list above, real projects are likely to cost more than indicated by the LCOE. Consequently, investors must do their own deeper studies to discover these. Likewise, investors who are interested in brownfield project development will need to source this information elsewhere (e.g. check AEMO publications) or do their own analysis.

Energy used in manufacturing costs are accounted for in capital costs. Notwithstanding the current difficulties in manufacturer profitability following the global supply chain crunch, to remain solvent, manufacturers must recover these costs (as with all other costs), in the long term, by building them into their technology prices. Also, the more that global economies track and potentially price greenhouse gas emissions, the greater the incidence of lifecycle greenhouse gas emissions of projects being built into technology prices. 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 reports and data break down the capital cost into three components: equipment, land and development and installation costs. Development costs are captured in the land and development segment. Aurecon (2024b) 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[42]. 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% or that all electricity sector emissions be completely eliminated. There is no such requirement in Australia under our net zero emission policy. Furthermore, going to 100% variable renewables would require the non-sensical step of shutting down existing non-variable renewable generation such as the existing Snowy hydro scheme and biomass generation. This approach denies renewables access to peaking plant such as open cycle gas turbines which are the most efficient technology for managing long periods of low renewable production but only result in residual emissions of a few percent compared to current electricity sector emissions.
- Limiting the types of storage technologies available to the system (e.g. only allowing batteries to participate rather than all storage options).

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[42] 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

- 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. In September 2024, the DOE (2024) republished research by Baik et al (2021) which some stakeholders also brought to the attention of GenCost and so we include this as well.

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.

Like Idel (2022), the Baik et al. (2021) research published in DOE (2024) initially sets up a scenario where solar and wind can only access battery storage to meet. No gas peaking plants are allowed creating an artificially high cost scenario. Baik (2021) then only allows nuclear, CCS, hydrogen or biofuels as additional firming options and finds the system cheaper under all of those combinations. The problem with this approach is that the initial system would have been cheaper had the gas peaking plant been allowed. Thereafter, it is unlikely that adding any of the other resources – nuclear, CCS, hydrogen and biofuels would have reduced costs. All of these other options for firming are more expensive than peaking gas. Baik et al. (2021) also makes the error of including only one type of storage technology- batteries.

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[43] power as the point of comparison. Australia's electricity system load is not flat. The cost of integrated VRE presented in GenCost is for delivery of reliable power to meet the system load.

[43] 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%.

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	Baik (2021) reported in DOE (2024)	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)	100% renewables with batteries or lesser shares of renewables with either nuclear, CCS, hydrogen or biofuel. Gas peaking plant disallowed	Considers 60%, 70%, 80% and 90% VRE shares
Limiting storage technologies	Only batteries are included	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	Multiple battery durations 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	Range of Californian profiles	Profiles for a wide range of Australian Renewable Energy Zones included
Limiting technologies that can meet system security requirements	NA	Synchronous generators only, but pumped hydro excluded	NA	Synchronous condensers, grid forming batteries and synchronous generators all available to be deployed

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 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 necessary for a moderate increase in VRE share to meet 2024 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 2024, 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 in the 2024 calculation, the 2030 result conforms to expectations of higher integration costs as the VRE share increases.

In reality, the calculated 2024 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 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 2024 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 who 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 generation technology[44], (based on either natural gas, renewable gas or hydrogen) hydro if it is available and transmission (to source diverse renewables that complement each other). In particular, peaking generation technology is a more cost effective means to provide generation in so-called 'renewable droughts'. When peaking plants 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 generation technology are not made available). Transmission and spilling electricity also reduce the need for more storage. In summary, 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

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[44] Such as a gas turbine or reciprocating engine

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

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

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

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

D.4.13 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 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 system cost studies. There are several Australian researchers and consultants capable of delivering such studies.

CSIRO has significant experience in conducting whole of electricity system studies[45] 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.

D.4.17 If GenCost shows renewables are cheaper, why are electricity prices higher in Australia and in countries transitioning to renewables?

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

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

In Australia, retailers, experiencing these conditions, secured electricity supply contracts for 2023-24 and factored these higher prices in. 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

[45] 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.

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.

D.4.18 If nuclear has such high capital costs why do they have such low cost nuclear electricity overseas?

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

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

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

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