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19 February 2024

Mr Daniel Westerman
Chief Executive Officer
Australian Energy Market Operator

Lodged by email: forecasting.planning@aemo.com.au

Dear Mr Westerman,

Submission to Draft 2023-24 GenCost

The Centre for Independent Studies (CIS) appreciates the opportunity to provide a submission to the Australian Energy Market Operator.

The CIS is a leading independent public policy think tank in Australia. It has been a strong advocate for free markets and limited government for more than 40 years. The CIS is independent and non-partisan in both its funding and research, does no commissioned research nor takes any government money to support its public policy work.

Our submission finds significant issues with the current Draft of GenCost, to the extent that the main conclusions drawn from the report — that integrated renewables are cheaper than all other sources today, and in the future — is incorrect and misleading. There are significant methodological inconsistencies in the way fossil fuel power is treated in the 2023 figures, leading to substantially higher LCOE estimates for these power sources. We also cannot reconcile the integration costs in the 2023 figures for renewables with the ISP scenario that is quoted as a reference. We believe that storage costs on their own might be underestimated by a factor of two.

Given the significance of this report to the public policy regarding the energy transition, we recommend CSIRO should conduct the analysis more thoroughly, so it can be demonstrated to be objective and rigorous. We also believe it is essential that CSIRO draw conclusions that fall outside the scope of AEMO's Integrated System Plan with confidence and credible independence from the opinions of AEMO as an organisation.

In the GenCost consultation webinar, Paul Graham stated that the CSIRO does not want to create a "competing set of modelling that sits next to the ISP" but would rather "use the ISP as the benchmark and not our work as their benchmark". We believe this is the wrong approach. It would be better if GenCost were an independent analysis that did not rely on the ISP being free of mistakes or omissions, and was capable of revealing them where present. But even if GenCost must rely on the ISP, as it currently stands, it should be consistent with it, and capable of independently drawing conclusions that the ISP's method is incapable of drawing.

The ‘overall’ cost of energy from a particular energy system, based on a dominant energy technology, is most certainly a conclusion that the ISP’s method is unfit to assess, and one which CSIRO’s GenCost should address — and claims to. The ISP’s model omits to factor in several costs, such as: Snowy Hydro 2.0; committed and anticipated transmission projects that have not undergone the RIT-T process; subsidies for coal plants to remain open; and consumer energy resources (including the necessary behavioural changes with respect to EV charging as well as distribution network upgrades). It also does not contemplate any policy scenario that does not include high targets for renewable energy, and a tight binding carbon target out to 2050. All optimisation in the ISP occurs within these constraints; making it impossible to compare the actual costs of alternative generation choices.

Given those limitations on the ISP, it’s of profound public importance that GenCost’s conclusions on these matters are credible and rigorous. Please find below our submission and recommendations to that end.

Yours sincerely,

Aidan Morrison
Director
Centre for Independent Studies Energy Program

Summary of Key Recommendations

- Correct the SMR construction costs to reflect Overnight Capital Costs only, consistent with other technologies
- Include serious consideration of large nuclear plants, which likely provide a lower cost nuclear option for Australia
- Correct asymmetric fuel price sampling methodology that biases towards high fuel costs
- Use forward-projected fuel prices consistent with the IASR in the LCOE calculation
- Adjust the capital cost of coal power stations to reflect realistic addition or replacement of coal power in Australia, not hypothetical green-field developments
- Move to a total-system-cost analysis for the integration of renewables, rather than a confusing and inconsistent 'costs faced by investor' approach at arbitrary timeframes
- Ensure that any costing of the integration of renewables is transparent, and can be reconciled with (or contrasted to) the Integrated System Plan, which currently demands far higher storage costs than is consistent with the 2023 integration
- Adjust the projections for batteries to be more consistent with recent historical trends, and other global literature

Contents

1. **Use of total costs for SMRs instead of overnight construction costs**

The report incorrectly compares total costs for nuclear SMR to overnight construction costs for all other technologies. On page 14, it is stated that “All costs are expressed in real 2023-24 Australian dollars and represent overnight costs” for coal, gas, solar and wind. Figure 2-3 then gives the current costs for SMRs as the equivalent to the UAMPS “updated real project costing”. This value is around A$30,500 per kW, which is calculated for the 462MW project using the total cost of acquisition and construction, including financing, which is US$9.3 billion.[1] The cost of SMRs is therefore greatly inflated because it is the only technology that erroneously had financing costs included in the cost estimates.

We submit that CSIRO should use only overnight costs for nuclear technology construction costs to ensure a level playing field. CSIRO was erroneous in making the statement that “Nuclear small modular reactors (SMRs) emerged as the highest-cost technology explored in the report,” a claim based on incorrect data, which was repeated by the Minister for Science and Minister for Energy and several media outlets at the end of 2023.[2]

2. **Failure to consider large nuclear plants**

Using a singular SMR data point as the cost estimate for nuclear energy plants fails to ensure a fair comparison with other technologies. The report states that “GenCost has been advised by stakeholders that small modular reactors are the appropriate size nuclear technology for Australia”, even though large-scale nuclear plants “are currently lower cost than nuclear SMR”.[3] As revealed by Paul Graham, the belief that SMRs are the only option for Australia was based on “face-to-face workshops in 2018 with industry groups”, in which there “weren’t any nuclear experts” simply because it “wasn’t on their radar at the time”.[4]

Instead, there were “generation companies, transmission companies, developers” who apparently asserted that “large scale nuclear isn’t the right size for Australia” which was “reinforced by the government of the day which was very focused on SMRs.”[5] Because CSIRO “didn’t get a lot of feedback that we were on the wrong path,” they continued using this assumption as the basis for excluding large-scale nuclear in GenCost reports from 2019-20 until now.[6]

In fact, CSIRO was given feedback that they were on the wrong path; with Nuclear for Climate Australia expressing concern in 2021 over GenCost’s exclusion of large nuclear plants despite reasonable cost estimates for this technology being more readily available than for SMRs.[7] This concern, along with suggested cost estimates that could be used, was repeated by Barrie Hill, Managing Director of SMR Nuclear Technology Pty. Ltd. and former Director of Engineering for ANSTO, in his submission to the 2022-23 Draft GenCost.[8]

SMRs are not the only — or necessarily even the most suitable — form of nuclear energy plant in the Australian context. As stated by the Australian Nuclear Association in its submission to the 2019 federal inquiry into the prerequisites for nuclear energy in Australia, “The nuclear generation units suitable for installation in Australia could be the currently operating APR1000+ pressurised water reactors (PWR) designed and manufactured by South Korea, and NuScale’s Small Modular Reactor (SMR) currently being licenced by the USNRC”.

It goes on to state that the large nuclear reactor APR1000+ is the only option “currently available that provides the opportunity for early ordering together with the lowest overall risk profile and value for money.”[9] Nuclear for Climate Australia reiterated this point in its submission that South Korean plants would be appropriate, stating that “suitable Nuclear 1GW sized Power Plants are available for installation on the NEM and these could be readily integrated with Small Modular Reactors as and when these become available.”[10]

Another reason given for excluding large nuclear reactors is that, to avoid the challenges to the grid of planned maintenance or unplanned outages, they would have to be “rolled out as a fleet that supports each other which represents a much larger investment proposition”. However, the need to roll out reactors as a fleet is not a valid reason for excluding them from a proper cost analysis, as a more credible cost analysis may well support the proposition that a large fleet of nuclear is economically and environmentally beneficial. Assuming that widespread adoption is not possible as a constraining input is an unfair and unreasonable bias against the technology.

It is also unreasonable to assume that the contingency for a large unplanned outage cannot be resolved through other investments in supporting infrastructure. The need for renewables to be supported by additional systems in order to make up for their intermittent nature shows a clear methodological precedent here. CSIRO argues that even with the cost of those additional investments to make up for intermittency, the overall cost of renewables is still low. The exclusion of such an approach in the case of large-scale nuclear, which has significantly lower costs than smaller reactors, represents another fundamental bias against nuclear in the analysis.

It appears that nuclear technology has not received the same level of detailed analysis as other technologies in GenCost because AEMO and CSIRO “don't spend a large amount of resources investigating the latest global trends” because of nuclear energy’s “legal status”, as stated during the 2019 Senate inquiry.[11] However, as Barrie Hill stated in his 2023 submission, “Current legislated nuclear power prohibitions should in no way compromise rigorous and professional investigation by CSIRO for planning level documents”[12] — this is especially pertinent, given there is a real possibility that legislation could change in the span of a few years, and governments need accurate information on which to base their policy decisions.

We submit that CSIRO and AEMO should either:

1. allocate sufficient resources to conduct proper consultation with nuclear experts on the types of nuclear plants that would be appropriate in the Australian context — as well as the estimated costs based on overseas projects — and include rigorous analysis of large nuclear plant costs in GenCost alongside other technologies; or
2. exclude nuclear technologies altogether from analysis if the issues raised in this submission are not adequately addressed.

This will prevent misleading communication of the report’s findings as definitively showing nuclear plants are more expensive than renewables; when a rigorous analysis has not been conducted.

3. **Unequal treatment of low and high coal price assumptions**

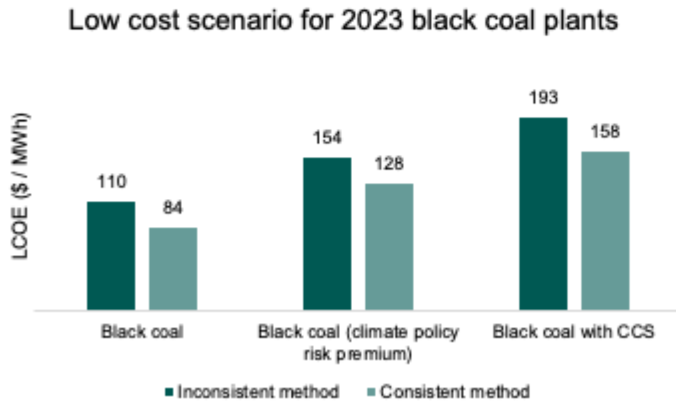
There is a particularly egregious error in the way CSIRO has calculated 'low' and 'high' assumptions for the GenCost black coal price estimates.[13] The low assumption for each year appears to have been calculated by taking the average of the individual coal plants' 'low price' values in the 2023 IASR, while the high assumption appears to have been taken as the maximum individual value for that year, with the 2050 high assumption using the higher 2040 maximum.[14]

	GenCost Black Coal Price Assumption	Average of IASR Black Coal Forecast	Min/Max of IASR Black Coal Forecast
2023 Low	$4.3	$4.3	$1.4
2023 High	$11.3	$4.8	$11.3
2030 Low	$2.7	$2.7	$1.5
2030 High	$4.1	$3.0	$4.1
2040 Low	$2.5	$2.5	$1.5
2040 High	$3.8	$2.9	$3.8
2050 Low	$2.5	$2.5	$1.5
2050 High	$3.8	$2.8	$3.6

This is inconsistent with the method used for calculating gas prices. Gas prices appear to have been taken from the 2023 IASR, with the low assumption being the minimum individual new-build cost and the high assumption being the maximum individual new-build cost.

Coal has no new-build projections, so the consistent approach would be to take the minimum and maximum individual values from existing generators. Alternatively, the average of the 'low price' values and the average of the 'high price' values could have been taken. However, there is no obvious reason why a lopsided approach of taking the average for the low and the maximum for the high would provide an accurate range of cost estimates.

The effect of this inconsistent approach is to artificially inflate the lower bound of coal price assumptions underpinning the LCOE estimates. This is especially noticeable for the 2023 prices, for which $4.30 per GJ has been taken as the low assumption, which represents a price spike resulting from Russia's invasion of Ukraine that is three times higher than the minimum of the individual prices for that year (i.e., $1.43 per GJ at Millmerran).[15] The figure below illustrates the sensitivity of the LCOE to the use of this inconsistent method.[16] We found that applying the consistent method of using the IASR's minimum individual value for the low assumption results in a sizable decrease in the lower bound LCOE for black coal (-24%), black coal with a climate policy risk premium (-17%) and black coal with CCS (-18%).



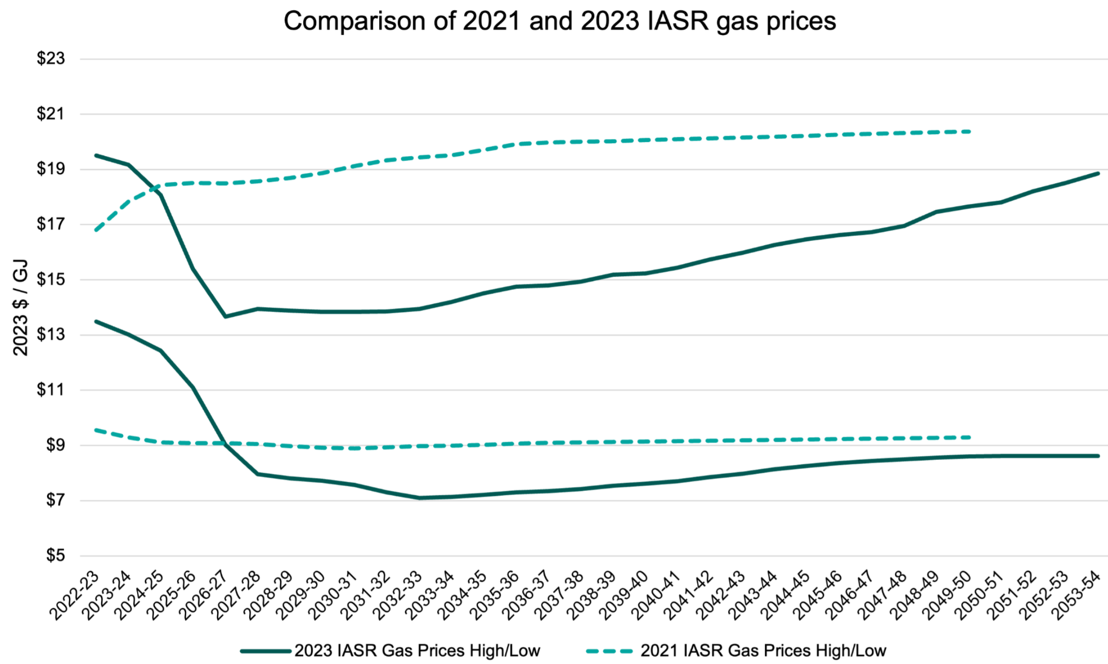
We submit that black coal costs should be calculated in a way that treats the low and high assumptions consistently (i.e., using either the maximum/minimum or the average of individual coal plant fuel prices for both calculations), instead of overinflating the lower bound LCOE by using the average value from the IASR while the upper bound LCOE uses the maximum value.

An alternative might be to consistently apply the average of the different prices contemplated in the IASR. This would have the impact of dramatically lowering the upper bound of coal, which saw particularly high, and short-lived estimates for only a couple of power stations dramatically increase the upper-bound of coal costs. In either case, a consistent approach is crucial to defend the integrity of the report. As it currently stands, a particularly egregious bias against coal is clear in the inconsistent methodology.

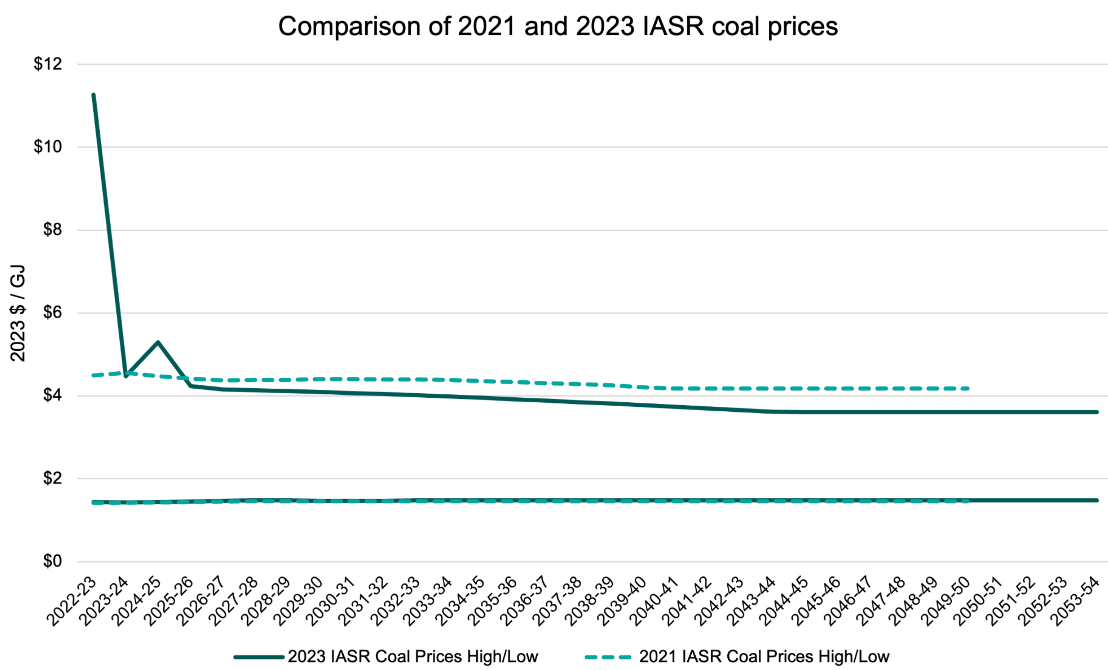
4. Unrealistic projection of fuel prices over time

The LCOE is calculated on the assumption that fuel costs in a given construction year are constant over the life of the plant. We believe this leads to inflated LCOE estimates for coal and gas plants built in 2023, largely due to a temporary spike in coal and gas prices due to the Ukraine war. This is reflected in the IASR and hence GenCost fuel price projections, with the low and high assumptions for gas price projected to fall from $13.50 and $19.50 per GJ respectively in 2023 to $7.70 and $13.80 in 2030.[17] The same occurred for black coal prices, which are projected to fall from a low and high assumption of $4.30 and $11.30 per GJ respectively to $2.70 and $4.10 per GJ.[18]

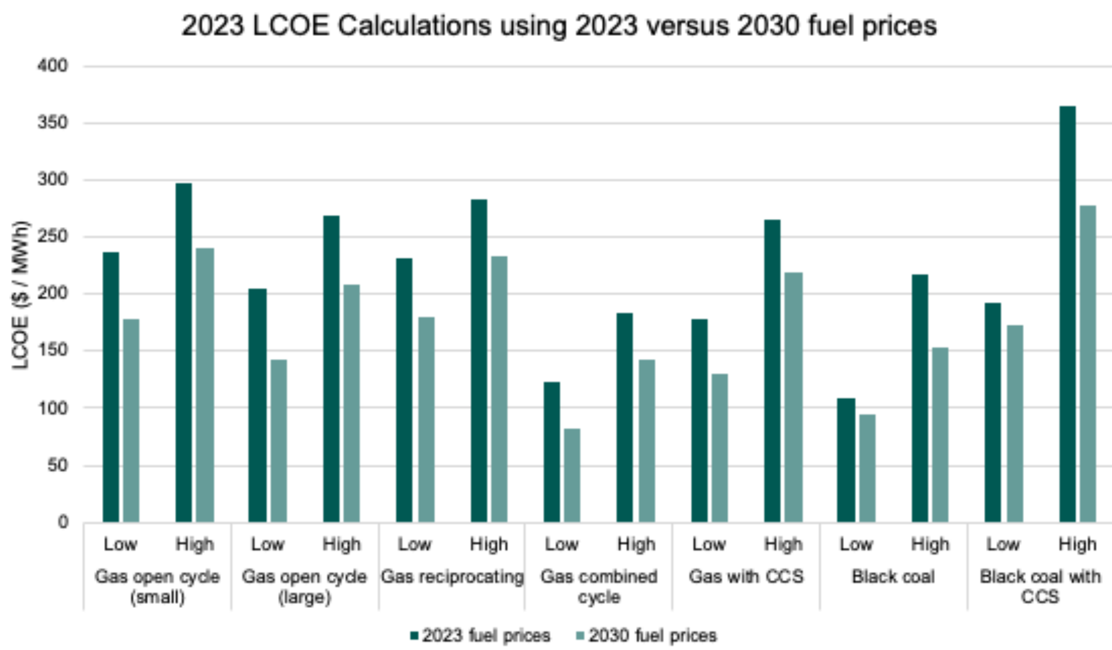
The outlier nature of the 2023 gas prices is illustrated by the substantial difference between the 2021 IASR (published before the war) and the 2023 IASR (published during the war). The 2021 IASR low forecast for gas prices remains at around $9 per GJ, while the 2023 IASR low forecast starts at a peak of over $13 per GJ before falling dramatically to $7-9 per GJ for the rest of the time series. The 2021 IASR high forecast starts at a minimum of $17 per GJ before gradually rising to around $20 per GJ, while the 2023 IASR high forecast starts at a peak of over $19 per GJ before falling dramatically to under $14 per GJ a few years later, then gradually rising to $19 per GJ.[19]



The outlier nature of the 2023 coal prices is even more striking, with the low price being the same between IASRs but the high price falling from a massive high of over $11 per GJ in the 2023 IASR to a more stable $4 per GJ in the space of a few years, while the 2021 IASR barely changes from just above $4 per GJ.[20]



Given that the temporary surge in fuel prices is projected to normalise over the next several years, it is unreasonable to lock in the inflated 2023 fuel prices throughout the economic life of generators, as was done in the GenCost modelling. This approach disadvantages coal and gas plants (which incur relatively higher fuel costs) by disproportionately increasing their LCOE compared to renewables such as wind and solar (which have no fuel costs). To illustrate the sensitivity of the LCOE model to this price spike, we substituted the assumed fuel prices of 2023 with those projected for 2030 in the GenCost LCOE model and found the LCOE for coal and gas plants across various configurations decline by an average of 22%, with some as high as 33% (i.e., the low LCOE estimate for gas combined cycle).



During the GenCost consultation webinar, Paul Graham said, "To get to the lower range in black coal and gas, you sort of have to have everything go right, a really good capacity factor, a really good fuel contract, those sorts of things."[21] This is a false and misleading statement. The truth is that we would always land in the lower range in black coal and gas, unless something (like a war in Ukraine) goes badly wrong.

We submit that the CSIRO can and should use the same forward-projected prices as the IASR throughout the timeframe of the LCOE model. This would still allow low and high scenarios to be contemplated, as the IASR has these alternative trajectories. Maintaining a present-day cost affected by a crisis that is out of line with all previous and future expectations for the full lifetime of the asset gives an unrealistic and biased view of prices. It amounts to assuming that we will have recurring wars every few years, or the market will never shift to resolve the impact of the current one, at any time, in the next 25 or 30 years. This is a grossly unrealistic assumption and another strong bias against these types of energy generation, compromising the integrity of the report and claims made from it.

5. Overestimated coal plant cost assumptions

The assumptions about coal plants contained in Aurecon's 2023 Costs and Technical Parameter Review, which is an input to the GenCost report, are fundamentally flawed. A new coal plant is assumed to be built on a greenfield site, with the combined expenses for land acquisition and development reaching $628 million. Additionally, the construction of a dedicated 50 to 100 km single track rail line dedicated for power station use is estimated to add another $210 million to the expenses.[22] In reality, a coal plant is far more likely to be built on or next to an existing coal plant site, which means equipment and construction costs could be substantially overestimated.

Furthermore, Aurecon chose the most expensive coal plant design available (i.e., advanced ultra-supercritical pulverised coal) which has never been used in Australia.[23] Fuel efficiency for coal plants is less important in the Australian context, as plants are typically built near a mine with plentiful coal reserves — which means it is better to build a cheaper plant that is less efficient rather than building an expensive advanced ultra-supercritical plant that is more efficient. Additionally, advanced ultra-supercritical plants require higher quality coal than is usually used in domestic coal plants, adding to the costs.

In his recent article, electrical engineer Ben Beattie compares Aurecon's technology cost assumptions with the actual costs of the Kogan Creek power station, a supercritical coal plant recently commissioned in the NEM.[24] Beattie finds that Aurecon's estimated costs are significantly inflated; the Kogan Creek station was built for $1.8 billion in 2023 dollars, substantially below Aurecon's projected cost of $3.1 billion. This considerable discrepancy of $1.3 billion sharply highlights Aurecon's inflated cost assumptions for coal plants.

Furthermore, the GenCost report states that "Aurecon (2023a) provides an update on the current costs of contracting the deployment of most of the technologies included in GenCost (biomass with CCS and brown coal are two exceptions)" but it is unclear from where the data for biomass with CCS and brown coal are sourced.[25] This should be clarified in the report.

We submit that GenCost should base coal plant cost assumptions on a more realistic plant in the Australian context, i.e., a supercritical plant on or near an existing site.

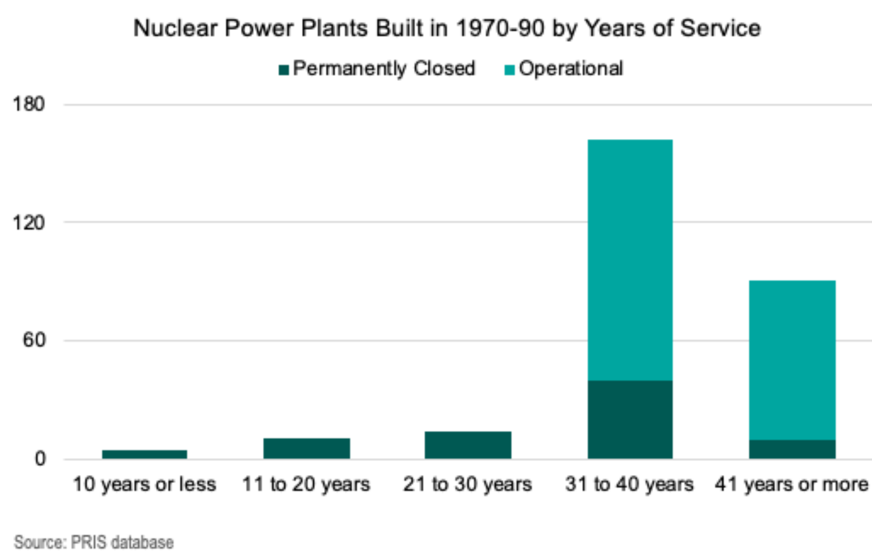
6. **Unrealistically short economic life for coal and nuclear plants**

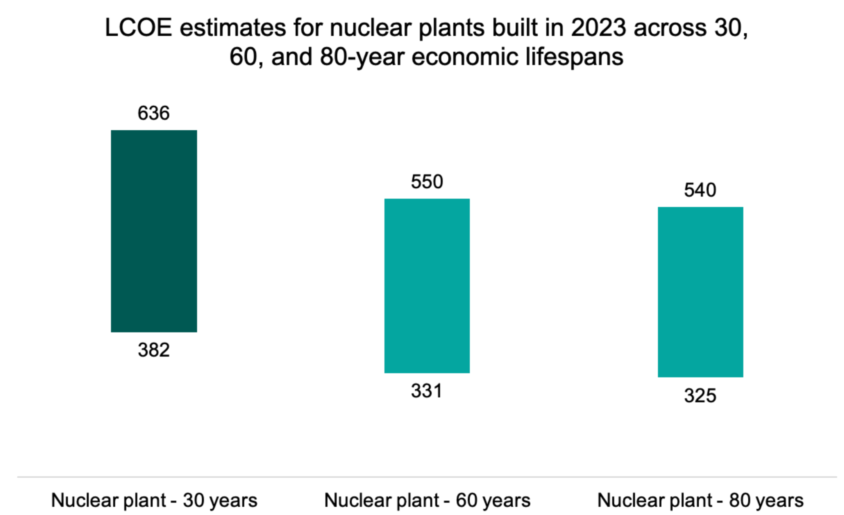
The report's estimation of the LCOE for coal and nuclear plants is based on a 30-year economic life assumption for both plants. This assumption stems from CSIRO's considerations of the design life or the financing period for a given generation technology.[26] Specifically, for power plants like coal or nuclear — which have a very long expected operational lifespan — the economic life used in calculations is not the total operational life but rather the financing period.

Paul Graham highlighted in the GenCost consultation webinar that CSIRO views banks as adopting a conservative stance, typically offering loans for a maximum of 30 years in accordance with the warranty period for major generation components of plants.[27] Graham noted that although these plants are known to last many decades, and this extended lifespan is accounted for in modelling retirement and stock turnover, the LCOE calculations use the expected loan financing duration capped at 30 years.

Such an approach inherently biases GenCost modelling against coal and nuclear power by underrepresenting the longevity of these plants, which often indeed last more than 30 years.[28] By defaulting to a presupposed financing term capped at 30 years, the report sets an unduly conservative economic life estimate, consequently skewing the LCOE for coal and nuclear plants upwards.

This systematically positions these two generation technologies at a disadvantage in economic comparisons, especially against renewable sources that tend to have much shorter operational lifetimes. Given that a large number of countries currently enjoy cheaper electricity due to having fully paid-off nuclear plants running beyond 30 years, some effort should be made to acknowledge or adjust for this lifetime difference.





Further, the decision to cap the financing period at 30 years overlooks the varied financing strategies employed for nuclear power and other large-scale energy and infrastructure projects that span beyond this duration. For example, joint venture approaches in Finland, known as the 'Mankala' model, have allowed energy producers to collectively finance large-scale power plants like hydro and nuclear, by providing equity in exchange for electricity supplied at cost price, in proportion to their shareholding.[29] Additionally, financing arrangements, such as the 35-year contract-for-difference (CfD) for the Hinkley Point C plant in the UK[30] and the issuance of 100-year bonds for railway projects,[31] demonstrate that there are funding mechanisms that extend well beyond a 30-year horizon.

We submit that CSIRO should use a more representative economic-life assumption for the coal and nuclear LCOEs to ensure a fair comparison with other technologies.

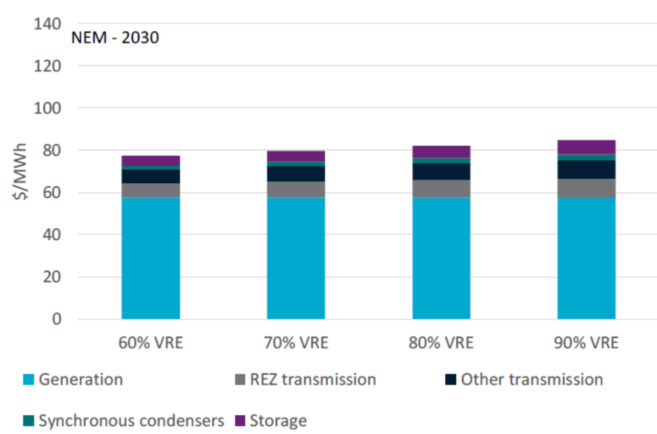
7. Costs for the integration of renewables

GenCost's claim that renewables are the cheapest type of electricity generation, even accounting for the cost of integrating them into a grid to make them reliable at high levels of penetration, is key to the political narrative and policy-making around the energy transition. The public has an interest in knowing the calculations in this regard are robust and transparent.

Whilst the latest consultation draft of GenCost does go some way to further explain the methods used, and highlight the key questions that the LCOE figures incorporating integration costs do (and don't) answer, there are still deep problems in the way this analysis and its results are conducted and presented.

Problems with 'sunk-costs' justified by considering only investors' perspectives

GenCost's key graphs are frequently used by renewables advocates to claim that high penetrations of renewables only have minimal integration costs. Unlike the typical findings of studies more rigorously costing the full system costs of the transition to renewables,[32] the graph in the 2022-23 GenCost showing the change in costs as more renewables enter the grid does not have the characteristic "ski-jump" shape. Instead, the increase in costs from 60% to 90% wind and solar generation is miniscule, remaining between $75-85 MWh (Figure 5-2).



This is because, as CSIRO's Chief Energy Economist Paul Graham states, the purpose of GenCost is to provide "two sets of data: capital cost data to be used by modellers and calculations of levelised cost of electricity (LCOE) data for new build generation capacity." In other words, GenCost is not concerned with calculating the whole-of-system cost of transitioning to a mostly-renewables grid, but only the cost for an investor, at a particular point in time.

Graham further clarifies that because LCOE data "calculates the cost per MWh that would have to be recovered for a new electricity generation investment to break even if it were to take place in a given year", GenCost "does not provide the cumulative cost of all investments up to 2030 because this is addressed in a separate project called the

Integrated System Plan of which GenCost is one of many inputs.” He further states that “all existing generation, storage and transmission capacity up to 2030 is treated as sunk costs since they are not relevant to new-build costs in that year.”[33]

What this means is that GenCost is not suitable for the purpose of determining the most cost-effective way to transition the grid, as it does not provide a full cost-benefit analysis of the various options. It is therefore only useful as a guide to investors wanting to build new solar and wind farms, as the enormous costs of large-scale transmission and storage projects that are planned to be finished before 2030 are ‘free capacity’[34] for the 2030 investor — but not for the consumer.

The 2023-24 GenCost report claims to solve this problem of integration costs being treated as free before 2030 by adding a new analysis, “integration costs for renewables in 2023 in addition to 2030.”[35] However, the continued presentation of the 2030 figures using the same method as before continues to provide a deceptive image of the energy transition. As clarified by Paul Graham in the GenCost consultation webinar, no accelerated depreciation of assets is allowed for in calculating the annualised 2023 integration costs,[36] so the idea that they will effectively be provided ‘free’ to the investor remains extremely misleading. There is no plausible world in which they would actually be provided free to the 2030 investor without additional significant costs being passed directly to consumers or taxpayers. So, the ongoing presentation of the 2030 integration costs remains a deceptive exclusion of significant total system costs, and a very poor guide to public policy and commentary.

The inconsistency in the logic of the method is also exposed in the rationale given to including transmission projects in the integration costs. Transmission costs in Australia are currently borne directly by consumers. There is no policy or method by which generation investors are ever fully expected to pay the transmission costs on which their project depends. Arguing that an investor would need to recover costs associated with transmission is therefore already a considerable abstraction from reality, in order to give a closer account of the full system costs, as opposed to those typically faced by an investor. It’s a substantial departure from what people typically consider to be investors’ costs. Arguing that ‘existing capacity available’ at a particular date is ‘free’, is a dramatic departure from the reality of what is faced by end-users, who bear the full system costs. Arguing that this is correct, or justified, on the basis that it tightly adheres to the reality of how costs normally apply to an investor, contradicts the premise that we must abstract from the realities of our present system to better reflect full system costs.

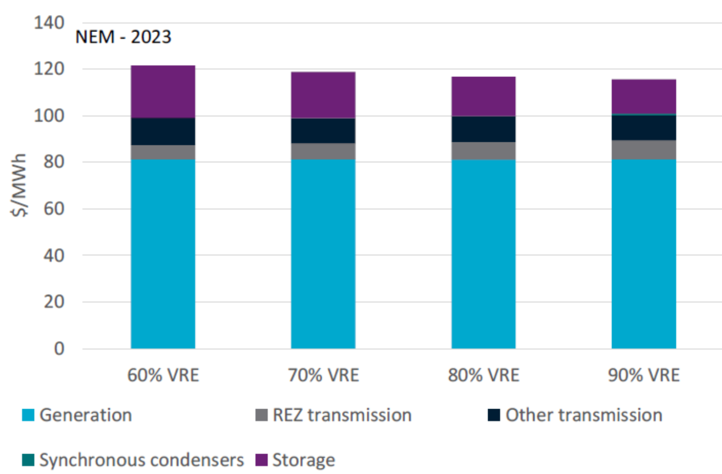
The end result is an analysis that is confusing, mis-understood, and easily cherry-picked by vested interests or politicians to suit their particular purpose.

We submit that GenCost should commit to a complete assessment of total system costs, as would be faced by end-users (or taxpayers) rather than confusing things by limiting it to an investor. If this revision is too dramatic to be undertaken in the time available, GenCost should wholeheartedly embrace a more limited scope of analysis that is restricted to costs faced by investors in our current system, and repudiate any commentary that makes any claims that this reflects the 'integrated' costs of renewables, as might be faced by end-users.

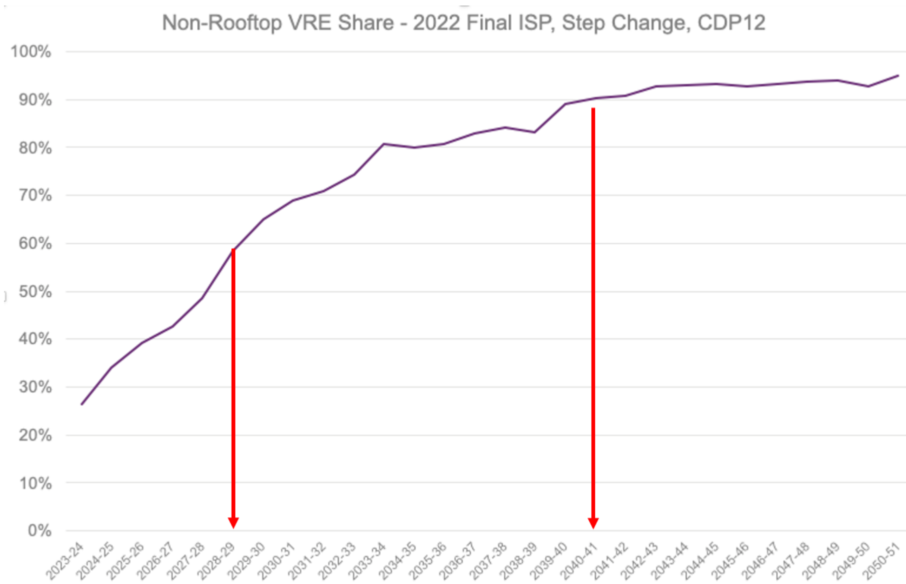
Problems with the 2023 integration of renewables calculation

The projects included in the 2023 integration costs are "two gas-fired power plants", "an additional 2 GW of at least 8 hours duration storage" in NSW and "Snowy 2.0 and battery of the nation pumped hydro projects … as well as various transmission expansion projects already flagged by the June 2022 ISP process to be necessary before 2030."[37] According to the 2022 ISP, this list of transmission projects expected to be complete by 2030 includes three 'committed' projects (VNI Minor, Eyre Peninsula Link, QNI Minor), four 'anticipated' projects (Northern QREZ Stage 1, Central West Orana REZ Transmission Link, Project EnergyConnect, Western Renewables Link), and four 'actionable' projects (HumeLink, Sydney Ring, New England REZ Transmission Link and Marinus Link Cable 1).[38] The report says that "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."[39]

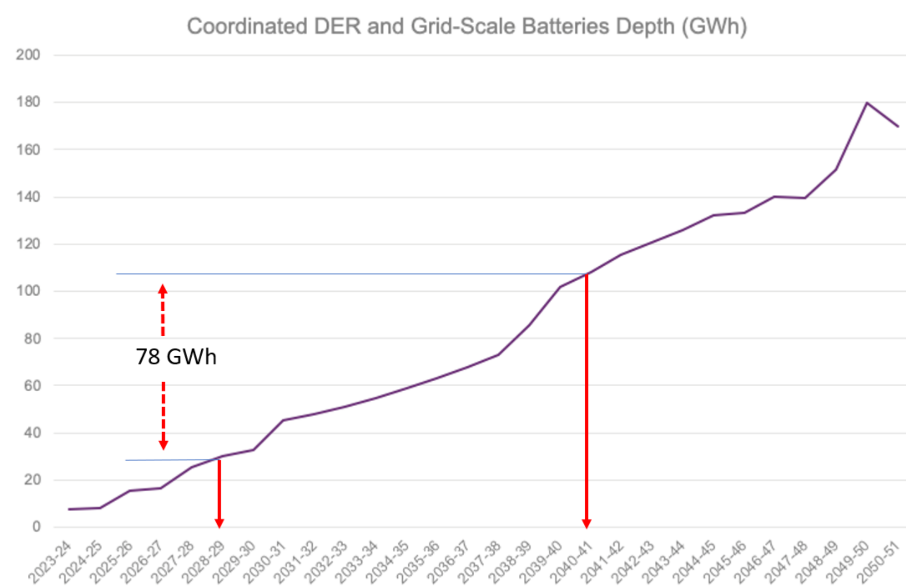
However, the CSIRO has not calculated what proportion of integration costs arising from these projects is necessary at each % VRE share. Instead, "these costs are included regardless of the VRE share".[40] This results in 2023 integration costs falling with increasing VRE share "because the cost of the committed storage and transmission infrastructure can be spread over more of the additional renewable generation the greater the required variable renewable share".[41] Whilst we can comprehend the method that has been applied here, the impact of this decreasing trend to most consumers of the report must be confusing, and potentially misleading, as reaching higher VRE shares is definitely not likely to require lesser integration costs.



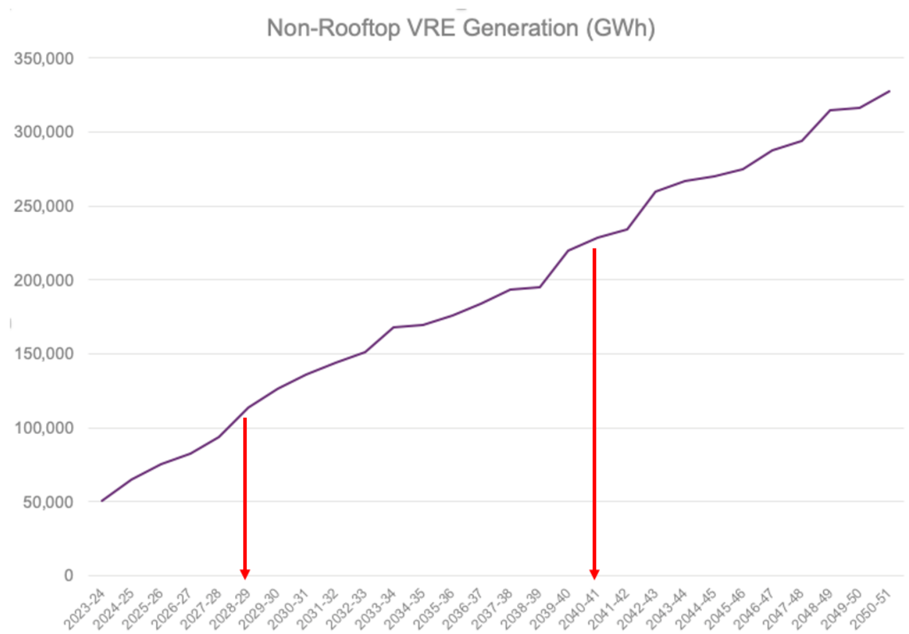
Furthermore, we find that the integration costs claimed for the 2023 analysis to reach 90% VRE share aren't credibly consistent with the ISP, and seem unreasonably low. In the 2022 ISP, 60% VRE (excluding rooftop solar) is reached in 2028-29, while 90% VRE is reached in 2040-41.[42]



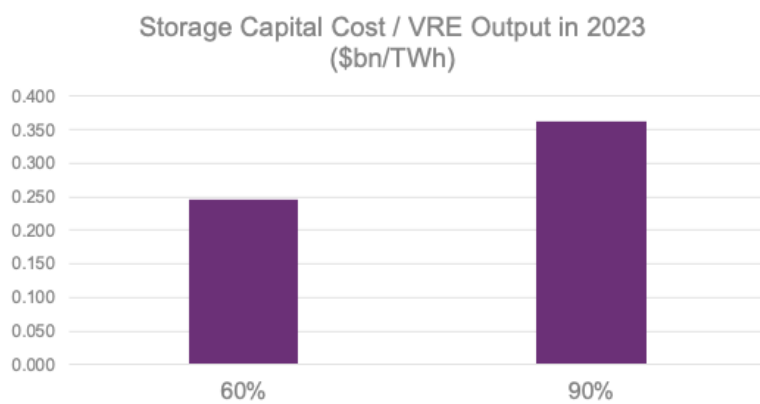
The difference between the coordinated DER and grid-scale battery depth required in these years is 78 GWh.[43] This comes to approximately $55 billion worth of batteries, taking the 2023 price of roughly $700/kWh.[44]



The amount of energy generated by VRE sources goes from 113 to 228 TWh between 2028-29 and 2040-41, almost exactly doubling output (accounting for curtailment).[45]



Taking the capital cost of storage (in billions of dollars) required at 60% VRE and 90% VRE and dividing it by the non-rooftop solar VRE generation (in TWh) at these VRE shares shows the ratio between capital cost and VRE output increases with an increasing share of VRE. This is at odds with what GenCost claims: that the 2023 LCOE storage costs decrease with increasing VRE share.



Although this analysis excludes operating costs that would be included in the LCOE, opex is very low compared to capex for batteries and pumped hydro, especially considering batteries need to be replaced every 15 or so years. Including opex would likely push the cost of storage even higher at 90% VRE share, since there will be a much higher proportion of batteries than pumped hydro compared to the proportion at 60% VRE share.

Furthermore, a simple check of the annualised costs associated with batteries that might have a capital value of $66 billion (from above, $55 billion plus the cost of the NSW batteries at $11bn) would suggest a cost of approximately $36 per MWh. This is far more than the roughly $17 billion suggested by the 2023 90% VRE share in Figure 5-2, which should also include costs for pumped hydro such as Snowy 2.0.

Battery Value	$66 billion
Depreciation (15-year life)	$4.4 billion
Cost of Capital (r = 5.99%)	$4 billion
Annualised Cost	$8.4 billion
Energy Delivered	228.5 TWh
Cost per MWh	$36.6 / MWh

We submit that CSIRO should clarify their calculations here, as the incorporation of sufficient storage to reach these higher VRE shares (if the 2022 ISP is used as a guide) does not appear to be consistent with the low cost arrived at in GenCost's LCOE calculation for integrated renewables. The provision of some more details about the particular transmission projects, and renewable capacities, included would greatly assist in providing transparency and credibility to the calculation.

It would appear that the adjustments required to make the integration costs credible for the 2023 calculation would be easily sufficient to reverse the conclusion that integrated renewables are generally cheaper than fossil fuels in 2023, and clearly so once adjustments to erroneous fuel prices are made. Unless the analysis can be done credibly and transparently to support the conclusion, it should not be included.

Use of ISP as a reference for 'reliable' integration of renewables

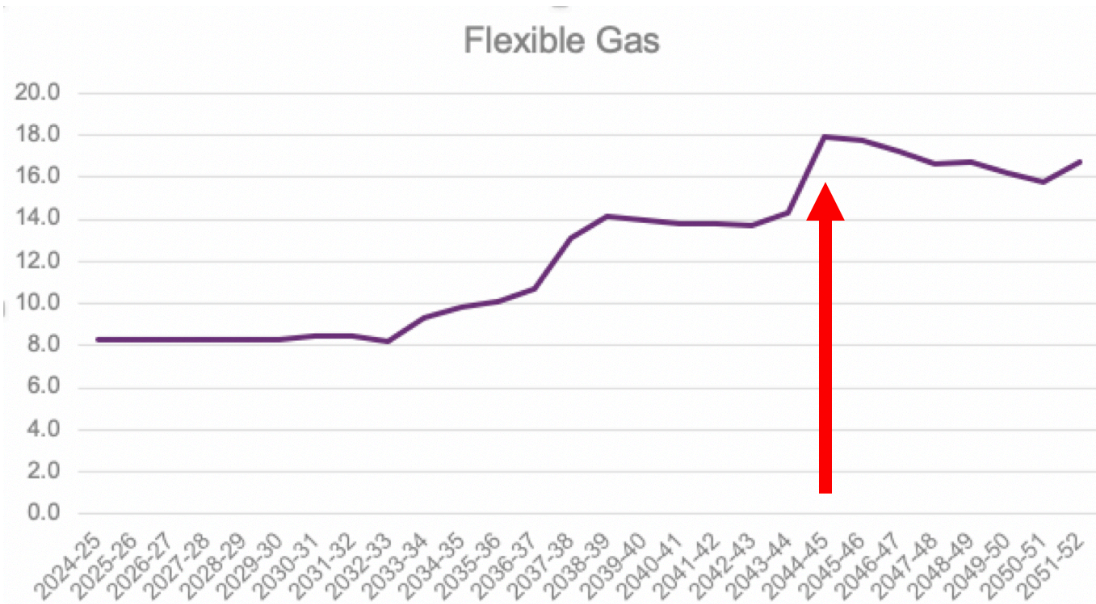
The ISP is not a fit-for-purpose model for determining the required investments to make renewables reliable. This was confirmed beyond any doubt in the August 2023 Webinar on the Capacity Investment Scheme, where Zoe Konovalov (Director, Targets & Modelling Team – Capacity Investment Scheme, Electricity Division, DCCEEW) made the following statements:

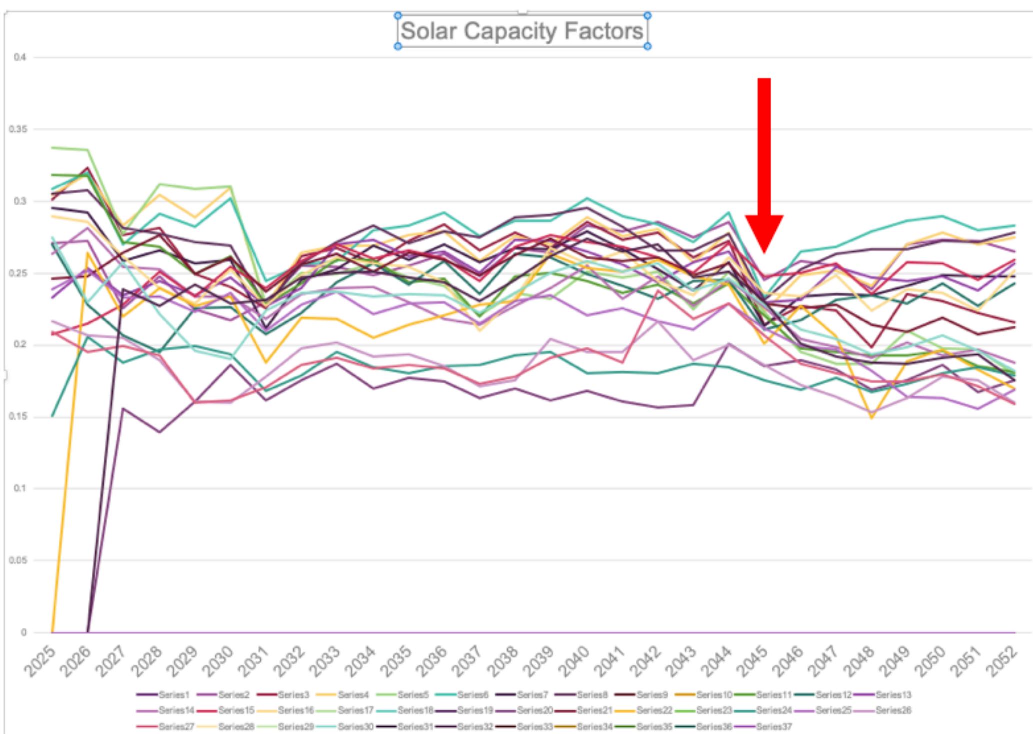
"And also, the original intent of the ISP as an exercise in transmission planning. It was not ever intended to be an exercise that would give you kind of, you know, reliability requirements across jurisdictions. So the modelers at AEMO that we talked to are, you know, kind of very clear eyed about the kind of roles of the various modelling exercises that they undertake."

This problem with using the ISP for reliability requirements derives fundamentally from the linear programs that are used to determine the optimal generation mix. They essentially lead to the assumption of perfect foresight in the model, allowing the generation mix to perfectly fit the demand profile, with generation outputs that match exactly a particular instance of weather patterns.

This leads to the installed capacities being unrealistically timed to exactly match with particular weather events in particular regions. In a realistic build, there would be no way of knowing when such events would occur, and the installed capacities of generation and storage would have to significantly increase to account for the unknown future.

This can be readily observed in the 2024 Draft ISP, such as this instance of additional gas capacity spiking in a particular year where solar capacity factors were depressed (probably due to an La Nina or other occasional weather cycles), shown below. Other instances of this unrealistic capacity profiles abound in the ISP Generation Outlook data of the current Draft ISP and earlier versions.





We submit that spotting this kind of methodological flaw, where a method that isn't fit for purpose is used to support the claim of reliability, is precisely what the public would expect of a federal scientific agency. GenCost should therefore not use the ISP as a reference point to confirm that the modelled proportions of storage/firming capacity required in GenCost are appropriate — as Paul Graham stated it does in the Webinar — but rather propose a better method, or adjustment to ISP estimates, that might actually be more credible and better accord with real reliability requirements.

Problem with assuming costs decrease when wind and solar are balanced

In the GenCost consultation webinar, Paul Graham states that "most states are heavy in one particular type of VRE", so as VRE share increases, "most of the states have to rebalance" towards being "less skewed towards one particular renewable" which apparently "offsets some of the curtailment issue" (i.e., increased curtailment at higher VRE shares) since it is apparently "cheaper to have a combination of solar and wind."[46] This does not make economic sense. If a state has more areas suitable for solar than for wind, investors will choose to build more solar farms than wind farms and they will build them in the locations that are cheapest first. This means as the VRE share increases, solar and wind farms must be built in progressively less ideal locations, increasing the overall costs. Building more of the less-favourable technology (e.g., wind farms in a state without many suitable windy sites) means that costs will increase. Therefore, the claim that the costs arising from increased curtailment are offset by having a more balanced combination of wind and solar defies normal expectations.

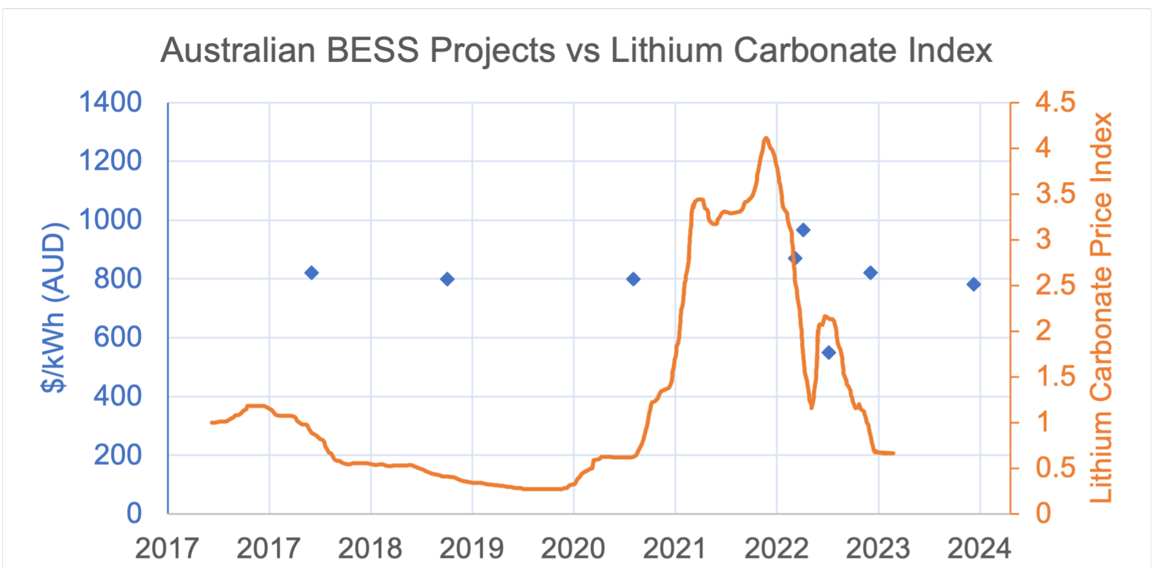
We submit that CSIRO transparently justify their method in order to support what appears to be an unreasonable conclusion.

8. Projected battery costs are too low and bear little relation to real world costs

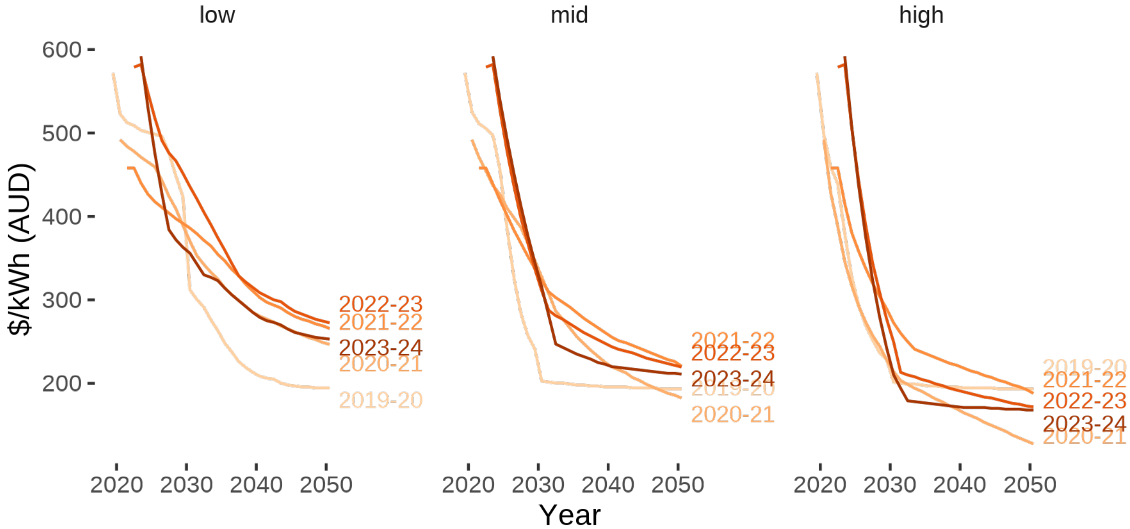
GenCost's battery projections are plagued by two significant problems. First, battery price projections have been consistently lower than both outcomes and credible international projections. Yet CSIRO continues to dismiss potentially fundamental market movements upward as a 'bubble'. Second, the projections seem to relate only loosely to real-world build costs for Australian battery energy storage systems (BESS), which have remained steady for almost six years. Combined, these present a significant problem for a system that will increasingly come to rely on BESS as the share of variable renewable energy increases.

In direct contradiction to the GenCost report's claim that "the projections for batteries is … reasonably well aligned with the previous projections", the per-kWh battery price projections have been consistently too low. Over the last three reports, the price projected for 2024 increased from $537 to $677 to $732 per kWh. It is critical that market movements are accounted for rather than ignored.

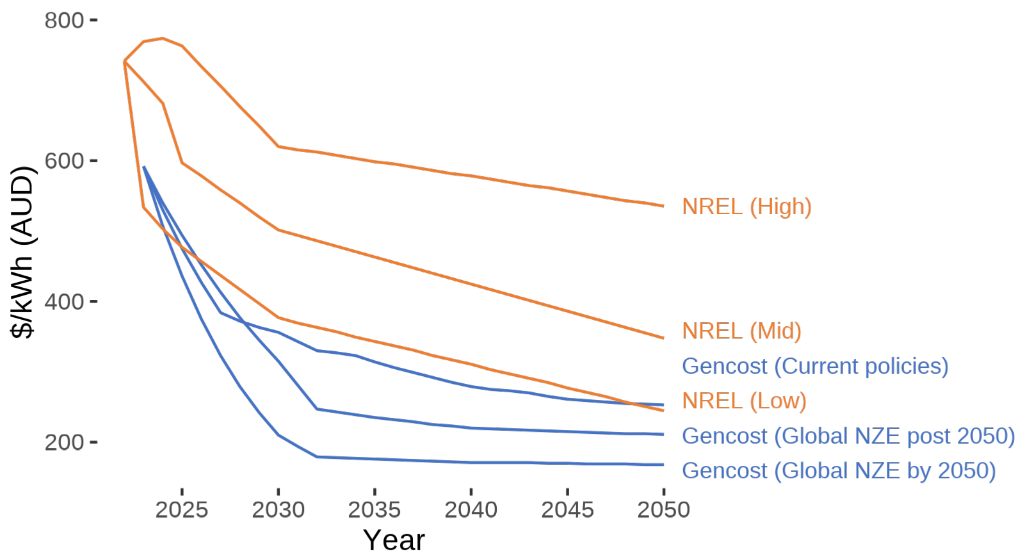
In ignoring these increases, GenCost argued they were a temporary "price bubble" and the result of a global inflationary environment, as noted by Steve Wilson in the GenCost consultation webinar, in which he stated "there was quite a spike in the lithium carbonate commodity price … that was a significant driver along with some of the other inflationary effects."[47] However, price movements of key underlying assets (Lithium Carbonate) seem to have failed to significantly drive Australian BESS project prices, as shown in the figure below. This suggests that other fundamental forces are far more important to battery prices than underlying asset prices.



Indeed, Aurecon believes that fundamentals are putting upward pressure on prices, reporting in 2023 that it was inflation "along with significant growth in the BESS industry leading to accelerating demand for BESS equipment and installation contractors".[48] This accelerating demand is precisely the kind of market conditions (aside from cartels or resource scarcity) that CSIRO describes when they argue that "to sustain real price increases … technology demand needs to grow faster than supply".[49] It is unclear how CSIRO justifies GenCost's 2023-24 battery cost projections dropping faster, and at some points being lower, than any previous projection. Projections are shown in the figure below, adjusted where appropriate to 2023 dollars.



Furthermore, Aurecon justifies the rapid reduction in prices by referring to the most recent NREL Cost Projections for Utility-Scale Battery Energy Storage[50] and suggesting that they also show cost decreases from 2023. However, both the NREL 'high' and 'medium' projections include sustained increases from the normal learning curve until 2030 and 2025 respectively. The figure below was created using 4hr total battery costs from the GenCost and NREL reports. It is unclear how CSIRO justifies the discrepancy between the shape of their projections and that of NREL's, as well as that of long-term prices.



We submit that CSIRO:

1. Provide more transparency around the derivation of projected battery storage prices.
2. Require Aurecon to benchmark projections against well-regarded international projections.
3. Account for fundamental drivers of prices such as accelerating demand where this is present.

4. Demonstrate how technology cost projections align with public information about projects that are complete, under construction, or planned.

9. Learning rates are opaquely sourced and apparently significantly outdated

The learning rate for mature nuclear technology (which we assume to mean light water reactors) has been set at 3%. However, this is essentially unreferenced, as the 2008 IEA report apparently does not contain a learning rate for large scale nuclear power. It would be valuable to know both how the learning rate of 3% has been derived, and why a 2008 version of an annual IEA report, of which a 2023 version is available, has been used throughout the learning rate section.

In regards to the learning rate itself, we recognise that estimating learning rates of large-scale nuclear energy can be difficult given the impact of local policies. Estimates such as Rubin *et al* (2015) set the average learning rate of nuclear since 1973 to between 0% and -6% but note that estimates for nuclear learning rates are confounded by the significant and exceptional regulatory burden and slowdown in construction that has prevailed since the 1970s in many countries. Notably, despite the poor track record in many countries, South Korea set appropriate policies and continued to build large-scale nuclear systems consistently over the last half-century and achieved a learning rate of 33%, showing that significant continued positive learning rates are possible with appropriate policies in place, even in a post-1973 global environment.[51]

We submit that CSIRO:

1. Provide accurate and up-to-date sources for learning rates.
2. Explain the derivation of learning rates where sources do not provide a learning rate itself.
3. Clarify whether learning rates assume for the given technology a reasonably best-practice policy environment, a most likely policy environment, or something else.

10. Missing figure

Figure 5-1 appears to contain an error, as it refers to "generation and storage capacity deployed in 2023 (left) and 2030 (right)" but there is only one figure and it is unclear which year the figure represents. This should be remedied to clarify the generation and storage capacity for each analysis.

Endnotes

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[5] Ibid.

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[7] Nuclear for Climate Australia, Submission to Comment on GenCost, Australia, pp 2–3.
[8] B Hill. 2023, Submission to Comment on GenCost 23 Draft Document Review, SMR Nuclear Technology, Australia.
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[13] P Graham et al., GenCost 2023-24: Consultation draft, pp 78–79.
[14] 2023 IASR Assumptions Workbook
[15] P Graham et al., GenCost 2023-24: Consultation draft, p 78
[16] GenCost Project Data, Apx Table B.9&10.
[17] P Graham et al., GenCost 2023-24: Consultation draft, p 78.
[18] Ibid.
[19] Low and high gas prices for each year were taken as the minimum and maximum of new-build gas prices in the 2021 and 2023 AEMO IASR Workbooks, with 2021 prices converted to 2023 AUD.
[20] Low and high black coal prices for each year were taken as the minimum and maximum of existing black coal plant fuel prices (excluding Lidell from 2021 due to its closure in 2023) in the 2021 and 2023 IASR Workbooks, with 2021 prices converted to 2023 AUD.
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[26] P Graham et al., GenCost 2023-24: Consultation draft, p 79.
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