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7 February 2025

Mr Daniel Westerman
Chief Executive Officer
Australian Energy Market Operator

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

Dear Mr Westerman,

Submission to Draft 2024-25 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 2024 figures, leading to substantially higher LCOE estimates for these power sources. We also cannot reconcile the integration costs in the 2024 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 energy transition policy, 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.

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

- Update large-scale nuclear estimates to reflect realistic capacity factor and lifespan assumptions
- Include integration costs in wind and solar capital cost projections
- Clarify synchronous condenser assumptions
- Include transmission project details to verify costs
- Clarify spillage costs and proportion of generation
- Update wind and solar capacity factors to realistic ranges
- Clarify assumptions driving demand load profile and ensure independence from the ISP
- Expand scope of coal buildouts beyond greenfield sites to include realistic new build units and refurbishments
- Include existing coal plant designs, not policy-driven expensive FOAK models
- Correct asymmetric fuel price sampling methodology and explain inflation discrepancy that biases towards high fuel costs

Contents

1. Unrealistic lifespan and capacity factor assumptions for large-scale nuclear

The report uses unfair assumptions about the lifespan and capacity factor of large-scale nuclear reactors. Despite Energy Minister Chris Bowen's claims to the contrary,[1] the latest report does not fairly reflect the typical lifespan and capacity factors of large-scale nuclear according to global precedent.

Previous iterations of GenCost calculated the LCOE of large-scale nuclear (and coal) based on a 30-year economic lifespan, rather than operational lifespan. This predetermined cap was used to reflect the typically conservative terms of project finance. This method underestimated the operational lifespan for nuclear.

The 2024-25 Consultation Draft is the first time GenCost acknowledges and attempts to address whether economic or operational life is most appropriate. Based on stakeholder consultation, CSIRO includes some analysis on extending the capital recovery period of nuclear over the entire operational life of the plant — around 60 years. However, CSIRO found "no unique cost advantages arising from nuclear's long operational life",[2] and elected to exclude the measured benefit that the operational life did reveal.

Including extension costs, GenCost found the longer lifespan of nuclear translates to an average cost reduction of 9% — levels that can be similarly replicated by other technologies under shorter capital recovery cycles. Over the same period, the complete rebuild of wind and solar was estimated to equate to 7% cost reductions, as the technological advancement would equate to lower required levels of investment the second time around. Based on the negligible cost reduction benefits found, CSIRO proceeded with the 30-year lifespan assumption for the LCOE estimates for nuclear; meaning the common interpretation of the headline figures for nuclear were not a revised 60-year lifespan as claimed by the Energy Minister.

This assumption is an inherent bias against the economic viability of nuclear (and coal) plants, especially when compared to the shorter operational lifespan of renewables. Many countries benefit from lower electricity costs due to fully-depreciated nuclear plants operating beyond 30 years, showing the need to fairly adjust for this lifespan disparity in economic assessments. Further, the residual value of a 30-year-old nuclear plant in the cost could be readily recouped by the investor by selling the plan to another operator free of debt. This evaluation of residual values is common and accepted practice for time-limited evaluation of the benefits of investing in long-lasting infrastructure.

GenCost assumes significant capital cost reductions of renewables over time. While cost reductions driven by technological advancement of solar panels or wind turbines may be plausible, these cost projections omit the replacement of system infrastructure required to firm intermittent generators — namely storage. Assuming degradation rates outlined in the IASR,[3] batteries can expect at least three replacement cycles across a 60-year lifespan. Factoring in replacement storage costs would likely mitigate the projected cost reductions for wind and solar. Of course, nuclear would not require anywhere near the commensurate levels of storage.

Had the cost projections included the system costs required to firm the renewable generators, we could expect much more favourable cost reduction advantages associated to the long operational life of nuclear comparative to wind and solar. We submit that CSIRO should run a fair LCOE analysis that reflects the operational lifespan of nuclear, and includes the storage costs required to support 90% VRE grid over the updated lifespan.

Further, the decision to make fixed-window comparison of system costs that could be filled by multiple sequential (or single long-lasting) projects is a substantial methodological break from the established GenCost practice of basing the analysis around LCOE; which is meant to focus on individual projects and evaluation over their lifetime.

The capacity factor assumptions for nuclear — namely the lower bound — are unrealistic. GenCost assumes a 53-89% capacity factor range for large-scale nuclear, when capacity factors in excess of 90% for large-scale nuclear are achievable according to US precedent.

Dialling back large-scale nuclear to make room for renewable capacity would be illogical. The GenCost report itself acknowledges that individual generators have previously achieved capacity factors more than 90% in Australia.[4] Specifically, GenCost highlights that some brown coal generators have achieved capacity factors over 90% due to significant fuel cost advantages. Given that CSIRO itself recognises nuclear fuel costs are likely to be even lower than brown coal by the 2040s,[5] the lower bound of the capacity factor assumption for nuclear is not a consistent or fair economic assessment. CSIRO should update the capacity factor range for large-scale nuclear to reflect a higher capacity factor.

Again, CSIRO's choice to make inferences about the capacity factor of nuclear based on coal is at odds with the LCOE modelling basis that the report purports to maintain; adopting the perspective of an investor. An investor in a nuclear project should be interested in maximising the returns for that particular project. This could, and should, involve building a large enough project to incorporate a degree of learning and benefit from economies of scale. This could be a large nuclear station of four or six reactors. However, there should be no compulsion to assume that a nuclear investor would commit to building 20GW in their initial investment decision, and so face the same degree of curtailment from renewables. Minimum load in the NEM is currently approximately 10GW, which provides ample space for economically efficient nuclear construction to occur, without approaching the level of penetration of coal at which higher levels of interference from wind and solar are expected.

A consistent application of the LCOE principles, from the perspective of an investor, should allow the best plausible case for a project to be assessed, rather than making arbitrary assumptions about subsequent projects (of any energy type) impacting their likely viability.

2. Misaligned renewables integration costs with ISP

GenCost's headline assertion continues to prevail: renewables are the cheapest form of electricity generation, even when factoring in the expenses of integrating them into the grid to ensure reliability at high levels of penetration. Since this is the prevailing political narrative shaping policy decisions surrounding the energy transition, it is imperative that these calculations are both rigorous and transparent.

The integration costs for 90% VRE claimed for the 2024 analysis to reach share are not credibly consistent with the ISP; with the estimated storage costs in GenCost being significantly lower. Given that Mr Graham has stated his objective to follow the benchmark of the ISP, more clarity must be provided to account for the discrepancies.

GenCost arrives at a total storage cost of $17.8/MWh for 90% VRE in 2024. Comparing this figure to the amount of storage required to support a 90% renewables grid outlined in the ISP, we submit that GenCost's storage cost figure is an underestimate. This was verified by subtracting the storage depth 2037-38 (when utility-scale solar and wind hit 92%) and the 2024 ISP Step Change ODP. This difference was multiplied by the GenCost capital costs ($/kWh)[6]. After applying discount rate and lifespan assumptions consistent with the ISP, our calculation of the storage costs reached a total around $25/MWh — 40% more than the CSIRO claim. CSIRO should provide its data to clarify this discrepancy with the ISP.

3. Biased assumptions underestimate synchronous condenser costs

The report underestimates the costs for synchronous condensers. Synchronous condensers help the grid withstand the instability caused by high penetrations of renewables. In the 90% VRE figures for 2024, they make up 0.3% of the cost share — to a tiny sliver of $0.4/MWh.[7] More clarity is required to explain CSIRO's logic in finding the costs for synchronous condensers to be this low.

CSIRO's reasoning for negligible synchronous condenser costs is a high penetration of existing synchronous generation (gas generators and hydro) that can fill the grid stability role.[8] But the report does not disclose data around how much gas capacity will be available, and why its cost should still be considered 'free' if the renewable share increases to 90%.

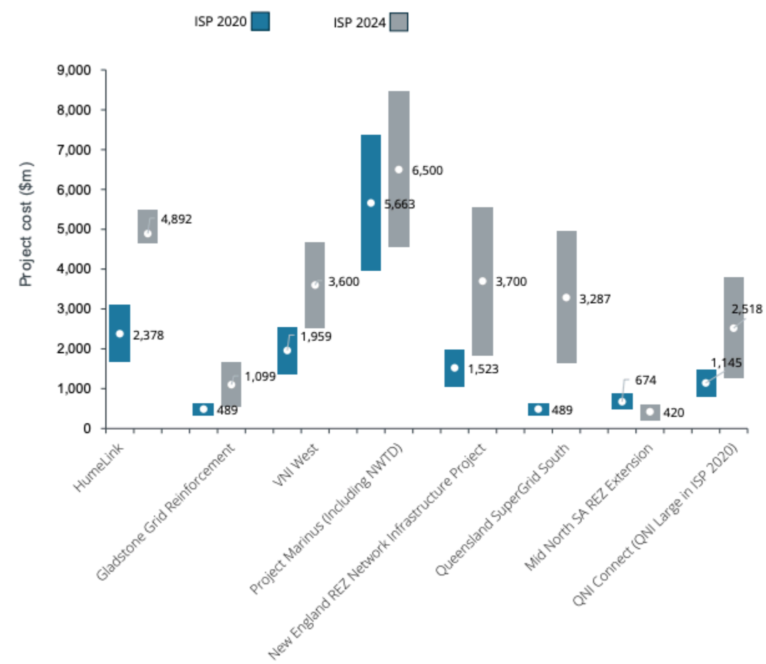
CSIRO should specify the total amount of spinning reserves for gas required in the 2024 90% VRE calculation. As VRE penetration increases, CSIRO acknowledges that synchronous condenser expenditure increases. Presumably, if existing gas generation provides spinning reserves to stabilise the grid today, their limited use would result in higher costs. Clarity is needed regarding the gas capacity required to reach negligible synchronous condenser costs in 2024.

4. Failure to disclose transmission projects and cost data

Between REZ and other transmission, GenCost accounts for the total cost of transmission in the 90% VRE scenario for 2024 as $23/MWh. This figure is impossible to verify as GenCost does not reveal which transmission projects are included in this figure.

Transmission costs are notorious for blowouts. Frontier Economics has shown that initial cost estimates for transmission projects in the 2020 ISP have consistently underestimated the revised 2024 cost estimates.[9] The ISP does not include committed or anticipated transmission projects in the costs. Given that the authors of GenCost consider the ISP as a benchmark, they are likely to be underestimating the cost of transmission projects as well.

Figure 13: Comparison of 2020 ISP and 2024 ISP transmission cost estimates



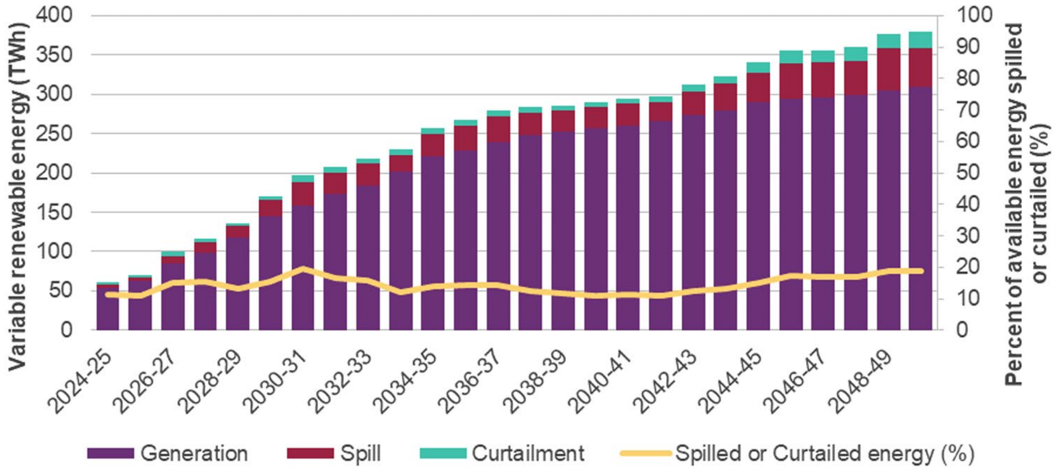
Source: Frontier Economics based on AEMO ISP and other sources documented in Table 6.

5. Spillage costs are contradicted, and percentage of generation spilled is underestimated

The cost of spillage is unclear in the report. The report states that “spillage costs peak at the 90% VRE share at $8.70/MWh in 2024.”[10] However, measuring the price in the graph finds spillage costs reach as low $4.30/MWh — less than half the value reflected in the report’s text. CSIRO must explain this discrepancy. It appears likely to either be an error, or that the peak spillage costs represented in the 90% VRE graph are taken from a lower VRE penetration.

Not only is there a clear contradiction in spillage costs, but there is a significant departure from the amount of spillage as a percentage of generation from the ISP. GenCost assumes spillage to equate to only 5% of generation. The ISP forecasts a much higher amount of spillage as a proportion of generation — closer to 12%.[11]

Figure 7 Forecast VRE generation and spilled or curtailed energy 2024-25 to 2049-50, *Step Change* (TWh)



AEMO's curtailed energy forecasts are already optimistically biased; smoothed by assumed-to-be-built hydrogen solar sinks and a significant uptake of coordinated consumer storage. It is unclear how GenCost assumes less than half the percentage of energy wasted than the ISP. If curtailment was forecast in GenCost closer to the 12% proportion of generation — as outlined in the ISP — the cost estimates for renewables would increase. CSIRO should publish the data to clarify the peak spillage costs at the 90% VRE share, and the assumptions and modelling behind the spillage percentage of generation which undercuts the already optimistic ISP projections.

6. Unrealistic wind and solar capacity factor ranges

The capacity factor assumptions surrounding wind and solar are overly optimistic in GenCost. For large-scale solar PV, the capacity factor range is 19-32%, and for onshore wind, the range is 29-48%. Our calculation on the actual grid scale renewable capacity factors in 2023 shows that these estimation bands are overly optimistic. Solar and wind reached approximately 19% and 29% respectively in the NEM in 2023[12] — meaning that capacity factors of both solar and wind in 2023 was around the minimum represented in GenCost.

Such wide discrepancy in the capacity factor ranges for integrated renewables invites too wide an error margin that skews the LCOE in their favour. System models like the ISP derive stand-alone capacity factors from the actual dispatch modelled from real weather years across all REZs. Capacity factors are generally not representative of the best or worst performance of the best generator in a given year, and as such, a more narrow range would be more plausible and a more accurate input into LCOE. For its integrated renewables costs, GenCost should rely on a single point value for capacity factors, reflecting realistic averaged actual production and dispatch volume derived from historical weather data, a realistic representation of system connections, and consideration of factors such as curtailment.

This approach ensures the capacity factors accurately capture the operational conditions of the system, and avoids understating the minimum credible total system cost which cannot avoid average capacity factors being realised across a range of REZs. Given that "integrated" renewables rely on the assumption that there is a large volume, and a variety of geographies spanned, the variance between individual project capacity factors is not relevant. A large integrated system must achieve only the average of the fleet.

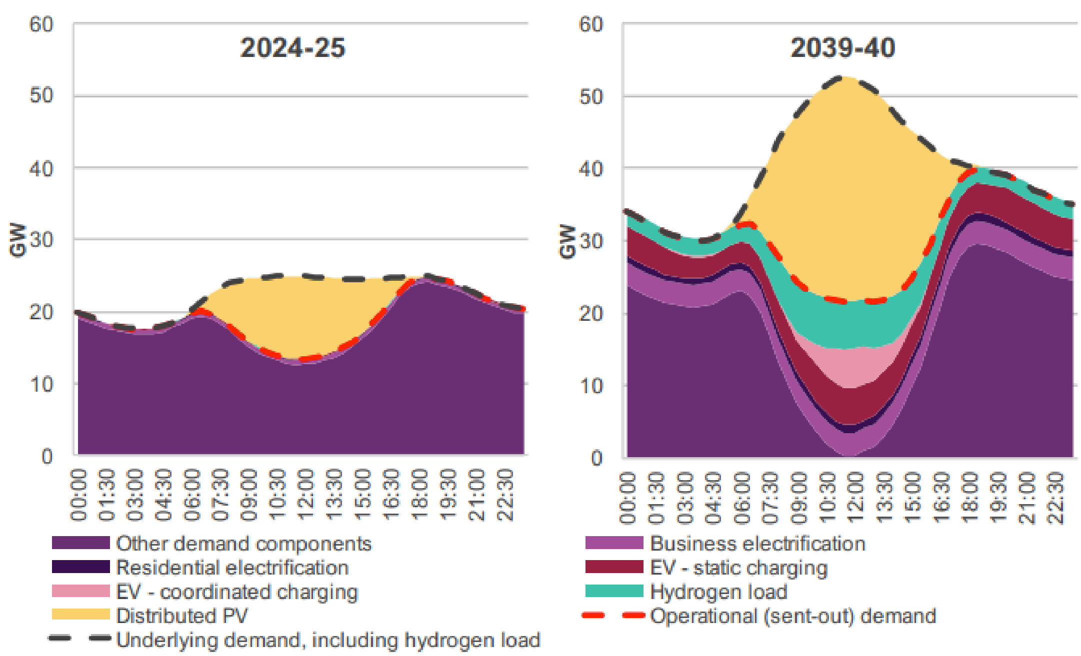
7. Ambiguity over demand load profile between GenCost and ISP

The report lacks transparency and clarity regarding key assumptions about demand load profiles and their interaction with high levels of VRE penetration; and specifically, how demand forecasts differ from the ISP. Demand projections potentially derived from the ISP without adequate adaptation or differentiation will likely include all the hidden costs and biased assumptions that smooth the demand profile duck curve in the ISP. This approach risks compromising the neutrality and robustness of GenCost assessments, which are intended to be policy neutral. We submit that GenCost should detail its own demand forecasts to prove its independence from the ISP.

Appendix 4 of the 2024 ISP outlines the duck curves for the demand load profile of the NEM in Step Change. In the 2040 figure, the curve is softened, due to behavioural consumption patterns, static EV charging, business electrification and hydrogen. These are not included in the costs of the ISP, so inheriting overly-optimistic assumptions of the demand profile in GenCost are likely to result in an artificially low LCOE of renewables.

Despite GenCost stating that 90% VRE share excludes rooftop PV,[13] it is unclear whether it is including its impact (alongside CER) in the demand load forecasts if they are modelled from the ISP. If CSIRO is indeed adopting AEMO's demand load profile without adjustment, there is a risk that GenCost inadvertently imports optimistic assumptions from the ISP. These assumptions may include high CER uptake and hydrogen solar sinks, which together smooth out demand load profile variances and reduce projected system costs. This risks masking the true challenges and expenses associated with integrating high levels of VRE.

Figure 1 Forecast average annual demand profile for the NEM, 2024-25 and 2039-40, *Step Change* (GW)



CSIRO should explain how its demand-load profile differs from AEMO's. CSIRO should explicitly detail how CER, hydrogen, and EV uptake assumptions influence demand profiles. A sensitivity analysis should quantify costs under alternate scenarios, such as delayed CER adoption. GenCost's demand forecasts must be distinct from the ISP, avoiding reliance on its policy-driven inputs. This includes modelling rooftop solar's full impact on residual demand and infrastructure requirements.

To maintain GenCost's status as a policy-neutral assessment, it is essential to clarify whether the 90% VRE share excludes rooftop PV while including its impact (alongside CER) in the demand load profile. Any such assumptions should be explicitly stated and, if found to be overly aligned with the ISP's policy-driven assumptions, should be recreated independently to ensure policy neutrality. CSIRO's demand load profile forecast has not been addressed in sufficient detail, and we request more clarity in the form of data or forecast graphs to be included to scrutinise GenCost's independence from the ISP's assumptions.

8. Exclusion of realistic new build units and refurbishments for coal costs

The treatment of coal in the GenCost is unfair due to three critical assumptions.

Firstly, GenCost does not consider the cost of coal beyond building new plants on unused, or 'greenfield' sites. New builds or refurbishments to existing plants are not included in GenCost, as Mr Graham erroneously assumes 'new build' is synonymous with 'greenfield'. This is a fundamentally flawed assumption and reveals a critical misunderstanding of GenCost. New coal plants can be constructed on either greenfield or brownfield sites, and this distinction has significant implications for capital expenditure and project feasibility. The current assumption in GenCost — that any new coal development must be on a greenfield site — results in unrealistic cost estimates that unfairly inflate the LCOE of coal.

Building on a greenfield site involves substantial development costs. The report assumes 20% of capital expenditure, or approximately $675 million, would need to be allocated for land acquisition and preparation.[14] Additionally, a further $1.14-$2.28 million is included for constructing a new rail line. These assumptions are based on the premise that no supporting infrastructure exists at the project site — but brownfield sites already have critical infrastructure in place, including established roads, rail lines, transmission lines, substations, office buildings, and water supplies. The availability of these facilities significantly reduces both capital outlays and project timelines. Many existing coal sites in Australia — including Mount Piper in New South Wales and Loy Yang B in Victoria — were deliberately designed to leave space for future expansion and could readily accommodate additional units.

If Australia was to build new coal generation, it would make no economic sense to overlook brownfield sites to build on greenfield. A 2018 GHD report, cited in previous GenCost editions, estimated the cost of refurbishment at between $120-$450/kW,[15] which is less than a tenth of the estimated cost for a new plant presented in the current GenCost report. On a like-for-like basis, assuming a 30-year operational lifespan for a new coal plant, a refurbishment providing a 10-year life extension at a cost of $300/kW represents less than a fifth of the expenditure required for a new build. We submit that the CSIRO must consider refurbishment as a legitimate option for coal to treat it fairly as part of an objective economic analysis.

9. **Include coal plant designs already in use, not expensive FOAK designs**

Despite claims to be a policy-neutral cost analysis, GenCost restricts its coal estimates to expensive, 'never been built' advanced designs — at the exclusion of existing plant designs. The report states: "Prior to 2023-24, the black coal capital cost had previously been based on a supercritical plant. However, an ultra-supercritical technology is the most plausible type given Australia's net zero by 2050 target," showing a clear policy-driven bias against coal.[16] The most recent coal plant built in Australia was a supercritical design. However, GenCost only considers advanced ultra-supercritical plants — a more efficient but more expensive design — at steam pressures and temperatures higher than any coal plant ever constructed.

GenCost sources the costs for black coal ultra-supercritical from the Aurecon Energy Technology Cost and Parameters Review. This very report outlines that "an advanced ultra-supercritical power station with the above main steam conditions is yet to be constructed."[17] Using a 'first of a kind' plant design on the basis of government policy contravenes GenCost's policy-neutral status and drives up the LCOE of coal.

CSIRO argues that new coal deployment is considered low plausibility in GenCost due to its high emission intensity, and Australia's bipartisan commitment to net zero by 2050. GenCost explains that the most plausible scenario for coal expansion would be pursuing designs that are most efficient, and that can be later retrofitted with carbon capture and storage (CCS); and given CCS incurs a fuel efficiency loss on the coal generator, the premium for efficiency in design choice is higher. Those arguments are incompatible with the claim that GenCost is a technology-agnostic and policy-neutral economic analysis. If the CSIRO wishes for GenCost to be interpreted as an independent, policy-neutral and fair economic analysis, we submit that it must include coal designs that would be realistic new build plant designs free from policy influence.

10. **Raw discrepancies and asymmetric fuel price sampling methodology that biases towards high fuel costs for coal**

Despite accounting for the Ukraine price spike (which pushed the lower bound of coal LCOE below that of 90% VRE), the CSIRO continues to employ asymmetric sampling methodologies to the fuel prices of black coal. The fuel prices are taken from the 2024 IASR, and still uses the 'average of the lows, highest of the highs' method. This means that for each of the low-value estimates, GenCost takes the average of the low IASR estimates for each coal generator. But for the high estimates, GenCost cherrypicks the maximum highest fuel price from the generators rather than the average; unfairly pushing up the upper band of the overall LCOE of coal.

	2024-25 GenCost (23-24 IASR[18] numbers)				
	CSIRO's values	**Average of IASR**	**Extreme of IASR**	**Unexplained change**	
2024 Low	$ 3.1	$ 2.9	$ 1.4	5%	
2024 High	$ 4.6	$ 3.0	$ 4.5		3%

2030 Low	$ 2.8	$ 2.7	$ 1.5	4%	
2030 High	$ 4.3	$ 3.0	$ 4.1		5%
2040 Low	$ 2.6	$ 2.5	$ 1.5	4%	
2040 High	$ 3.9	$ 2.9	$ 3.8		3%
2050 Low	$ 2.6	$ 2.5	$ 1.5	5%	
2050 High	$ 3.9	$ 2.8	$ 3.6		8%

A more consistent approach would be to take the minimum and maximum values of each individual generator. A consistent average of the 'low price' values and an average of the 'high price' price values would also have been appropriate. But using one average estimate and one maximum estimate is not a fair assessment.

We also submit that the chosen fuel price estimates are even more egregiously inflated beyond this unfair sampling methodology. Each estimate for coal — including the low estimates — have been inconsistently and inexplicably inflated between 3-8% of the average and extreme values. GenCost and IASR numbers are in real terms; so the reasoning for inflation on top of these values remains opaque. There is no discernible explanation for this method, and CSIRO must provide clarity around both the fuel sampling methodology and the inexplicable inflation in fuel costs, which are unfairly driving up the LCOE for coal.

Endnotes

[1] ABC, Renewables vs nuclear: Chris Bowen and Ted O'Brien debate Australia's energy future | 7.30
[2] P Graham et al., GenCost 2024-25 Consultation Draft, pp ix.
[3] 2025 IASR Draft report
[4] P Graham et al., GenCost 2024-25 Consultation Draft, pp 98.
[5] P Graham et al., GenCost 2024-25 Consultation Draft, pp 83.
[6] Difference in storage depth (GWh) between 2037-38 (when utility-scale solar and wind hit 92%) and 2024-25 in the 2024 ISP Step Change ODP was multiplied by GenCost capital costs ($/kWh). As GenCost assumes all batteries in 2024 analysis are utility-scale, coordinated CER was added to the shallow storage category. Cethana storage depth was subtracted from deep storage total. Shallow storage (2 hour batteries) and medium storage (8 hour batteries) were assumed to have a 20-year economic life, in accordance with GenCost. Deep storage, including 24 hour pumped hydro, Snowy 2.0, Borumba and Cethana were assumed to have a 30-year economic life in accordance with GenCost's treatment of generators. A 5.99% discount rate was applied in accordance with GenCost. Total storage costs ($/MWh) were calculated by dividing the annualised storage payment by the utility-scale wind and solar energy delivered in 2037-38 in the 2024 ISP.
[7] P Graham et al., GenCost 2024-25 Consultation Draft, pp 63.
[8] P Graham et al., GenCost 2024-25 Consultation Draft, pp 63.
[9] Source: Frontier Economics, Report 1 – Developing a base case to assess the relative costs of nuclear power in the NEM, pp 42.
[10] P Graham et al., GenCost 2024-25 Consultation Draft, pp 64.
[11] AEMO, 2024 ISP Appendix 4. System Operability, pp17
[12] 2024 wind and solar were calculated by taking the total GWh of energy generated (November 2023 – 2024) from OpenElectricity, and comparing with the installed capacity provided on the same website, adjusting for known wind farms that are listed there as being commissioned but were known to not yet be fully operational.
[13] P Graham et al., GenCost 2024-25 Consultation Draft, pp 60.
[14] Aurecon, 2024 Costs and Technical Parameter Review, 12 June 2024, p 56.
[15] GHD, Cost and Technical Parameter Review, September 2018, pp28.
[16] P Graham et al., GenCost 2024-25 Consultation Draft, pp 38-39.
[17] Aurecon, 2024 Costs and Technical Parameter Review, 12 June 2024, p 53.
[18] 2024 IASR Assumptions Workbook