


Australian Resources Development Pty Ltd

Submission regarding GenCost 2024-25 Consultation draft

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Agenda

GenCost25 Draft material understates the cost of integrated (or firmed) renewables

The major conclusion of the CSIRO's GenCost 2024-25 Consultation draft (**GenCost25 Draft**) is: "*The cost range for variable renewables with integration costs is the lowest of all new-build technology capable of supplying reliable electricity in 2024 and 2030.*" (Page 64).

This Submission demonstrates that the conclusion is wrong due to the major understatement of the cost of firmed variable renewable energy (**VRE**) generation technologies.

Major Understatements

- **Totally unrealistic assumptions about generation levels of new-build wind farms**:

  CSIRO assumes that the location of each MW of new-build wind generation capacity has a wind resource that will produce 85% more electricity than the average of each MW of operating wind capacity in 2024. The CSIRO's high range assumption for this rate of output (or capacity factor) is set at the highest historical maximum outcome of 48% which occurred in 2018.

  To set the average capacity factor for new-build plant at the historical maximum rate is contrary to the data about the capacity factors achieved by new wind farms and is totally unrealistic. The CSIRO describes this assumption as "plausible".

  Even the low range assumption is 10% higher than the actual 2024 average capacity factor.

- **The use of outdated and significantly understated transmission costs:**

  The construction of significant transmission capacity is required to transmit the VRE from remote locations to the major load centres.

  GenCost25 Draft understates the projected pre-2030 cost of this new capacity by over 100% based on an independent estimate drawn from public information.

- **The omission of several major costs that disproportionately affect the relative cost of renewables**:

  These costs include connection costs and transmission losses which are much higher for remote renewable generators and the costs of the various government subsidies required to support investment in renewable capacity.

- **Significantly lower levels of electricity storage required to ensure a reliable system relative to other modelling studies.**

When the understatements are corrected, integrated VRE technologies are not the lowest-cost new-build technologies

When the GenCost25 Draft's estimated levelised costs of electricity (**LCOEs**) are corrected for these unrealistic assumptions and the understatement and omission of major costs, the estimated LCOEs of integrated VRE technologies are significantly higher than the estimated LCOEs of dispatchable, coal and gas CCGT and large-scale nuclear generation technologies in 2024 and 2030.

Executive Summary (cont.)

Significance of the Gencost25 Draft uncorrected results

None of this would matter if the GenCost modelling was an abstract, academic exercise. However, the GenCost results are now at the centre of a political debate about Australia's pathway to a low carbon electricity sector.

This is because, while Net Zero 2050 policy has the bipartisan support of both Australia's major political parties, there is now a major argument over the lower cost path to achieving this policy:

- firmed VRE generation technology – current Federal Government; or
- development of dispatachable nuclear generation technology – Liberal National Party.

Significantly, the GenCost conclusion that integrated VRE is the lowest cost, new-build generation technology was seized upon by the Federal Government to support its energy policies in a media release entitled "*Experts agree: Nuclear only getting more expensive, slower for Australia's energy needs*".

The Frontier Economics reports

The Federal Government's comments were in response to the release of two independent reports by Frontier Economics (prepared at its own expense) that investigated the relative cost of the Federal Government's energy policy of achieving NZ2050 through firmed VRE generation technologies. The first report replicated the results of AEMO's 2024 Integrated System Plan (**ISP24**), using the same assumptions. As the ISP24 was designed to deliver the Government's policy, the results of this report provided a base case against which to assess the relative cost of adding nuclear generation to the generation technology mix. It was also designed to improve the debate on the potential introduction of nuclear generation in Australia.

The second report concluded that the introduction of nuclear generation would be significantly cheaper than the Federal Government's policy.

Thus, there is now an independent report from an energy-modelling expert that directly contradicts the GenCost25 Draft results and supports the major conclusion of this Submission.

Major issues with the LCOE Methodology

A major admission in GenCost25 Draft is that its LCOE methodology "… *is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance.* (Page 57). Indeed, the LCOE methodology is "... *designed to annualise all project costs into a single year. It is not well suited to costing a progression of projects over multiple years. Multi-year investment problems can be studied more appropriately in intertemporal electricity system models.*" (Page 61).

Significantly, the Frontier Economics' reports are based on sophisticated, more realistic and appropriate, intertemporal electricity system modelling.

Clearly, both conclusions cannot be correct.

Executive Summary (cont.)

Position in which the CSIRO has placed itself

The CSIRO, as a taxpayer-funded body, has now placed itself in the very difficult position as the most prominent source of expert advice supporting the Federal Government's energy policy based on firmed VRE generation technology being the lowest cost option. This advice has been challenged by an independent, energy industry expert that concludes that the Liberal National Party energy policy, based on the development of dispatachable nuclear generation technology, is significantly lower cost than the Federal Government's policy.

Issues the CSIRO should address in the final Gencost25 report

If the GenCost25 Draft results are to be considered credible, this Submission argues that the CSIRO should demonstrate clearly, in the final report, that the results are not being skewed towards firmed renewables as the lower cost path to NZ2050 relative to a nuclear path by:

- ❑ the self-identified deficiencies in the CSIRO's LCOE methodology; and
- ❑ the unrealistic assumptions and the understatement and omission of major costs in the GenCost25 Draft.

In resolving these issues, comfort can be taken from the statement of the CSIRO's Director of Energy, Dr Dietmar Tourbier, on the release of the GenCost 25 Draft: "*GenCost provides objective cost benchmarks using the best available and verifiable data. … GenCost's annual update delivers data-based forecasts that support informed decision making across energy sector …*" (CSIRO Media Release)

This is not to say that the transition to a low carbon energy sector is not important and worthwhile. However, this conclusion highlights the importance of Australian policy makers and stakeholders being better and more reliably informed of the likely future costs of the major pathways to making the transition to a low carbon generation sector.

Introduction

This submission (**Submission**) sets out a review of the "GenCost 2024-25 Consultation draft" (**GenCost25 Draft**) that will be submitted to the "2025 Inputs Assumptions and Scenarios Consultation" governed by the Australian Energy Regulator's (**AER**) Forecasting Best Practice Guidelines.The Submission makes reference to the documents listed in Appendix 1.

GenCost Purpose

The **GenCost Purpose** is to provide "key input data" for others to analyse "complex questions about the electricity sector …" (Page 57).

GenCost Methodology

The **GenCost Methodology** uses levelised costs of electricity (**LCOEs**) to summarise the relative competitiveness of new-build generation technologies.

However, the LCOEs for intermittent, non-dispatchable, variable renewable energy (**VRE)** technologies are not comparable with the LCOEs for dispatchable technologies such as coal-fired, gas-fired and nuclear technologies. Thus, the Methodology includes a second step of adding the cost of firming VRE technologies with additional **Storage** (largely batteries and pumped hydro). Storage represents and peaking plants plus additional transmission capacity to ensure achieving a reliable supply of electricity (**Firming**[1]). In effect, Firming converts the intermittent VRE electricity to dispatchable electricity.

The major sources of VRE are wind and solar, excluding hydro and rooftop solar PV and associated resources (**Rooftop PV**). Under the Methodology, Rooftop PV is deducted from demand .

Thus, the GenCost Methodology can be described as a two-step process:

1. the simple arithmetic to calculate the LCOEs for the various generation technologies (**Standalone LCOEs**); and
2. the more complex system modelling, akin to the ISP24 modelling by the Australian Electricity Market Operator (**AEMO**), to derive the Firming costs for VRE technologies.

GenCost25 Draft notes that: "*LCOE is a simple screening tool for quickly determining the relative competitiveness of electricity generation technologies. It is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance.*" (Page 57). Thus "*LCOE data can only answer a narrow range of questions*". (Page 57).

All references to wind generation technology in this Submission refer to onshore wind only. Reference to years is to financial years and all monetary figures are expressed in fiscal year 2024 (**FY24**) dollars.

1. The EPIA Paper referred to firming VRE on the basis that it was a well understood and widely used concept in the Australian electricity industry. The CSIRO Response stated that firming "… is not a term used in GenCost 2021-22 because it is ill-defined within the electricity industry. The author equates it with our definition of integration costs …" (Page 6). That is, firming and integration were different. Draft GenCost25 now states: "*In this report, where we make a comparison between the costs of variable renewables such as solar PV and wind and the costs of other technologies we include the cost of firming those renewables which we call integration costs*." (Page viii).

Focus of the Submission

This is the fourth Submission this organisation has made on GenCost including the EPIA Paper.

The focus of this Submission is:

1. The estimated standalone LCOEs.
2. The estimated Firming costs.
3. Other issues.

The Submission commences with:

- a review of the GenCost25 Draft results;
- a review of the Frontier Economics (**FE**) independent analysis of introducing nuclear generation technology to achieve emission targets; and
- the response to the GenCost25 Draft results in the context of the Australian energy policy debate.

GenCost25 Draft Results

The results from GenCost25 Draft (Apx Table B.10 page 84) for the low assumptions in FY24 and FY30 are reproduced in Table 1 for selected dispatchable, baseload and VRE technologies expressed in FY24$/MWh.

The **Firmed LCOEs** for large-scale solar PV (**Solar PV LS**) and wind are derived by adding the estimated VRE Firming costs for 60% and 90% VRE shares[1] of total generation (**VRE Shares**) (page 64) to the standalone LCOEs for Solar PV LS and wind.

Table 1: GenCost25 Draft Results

Technology	FY24 - Low	FY30 - Low
Black coal	$102	$92
Gas CCGT	$128	$85
Nuclear – large scale (**Nuclear LS**)	$155	$150
Standalone		
Solar PV LS	$43	$35
Wind	$70	$56
Firmed		
Solar PV LS - 60% VRE Share	$91	$55
Wind - 60% VRE Share	$118	$76
Solar PV LS - 90% VRE Share	$85	$85
Wind - 90% VRE Share	$112	$106

Based on these results, the GenCost25 Draft concludes:

"*The cost range for variable renewables with integration costs is the lowest of all new-build technology capable of supplying reliable electricity in 2024 and 2030. The cost range overlaps slightly with the lower end of the cost range for high emission coal and gas generation. However, the lower end of the range for coal and gas is only achievable if they can deliver a high capacity factor and source low cost fuel. Their deployment is also not consistent with Australia's net zero by 2050 target.*" (Page 64).

The referenced "*net zero by 2050 target*" encompasses the Net Zero 2050 policy (**NZ2050**) to reduce Australia's net greenhouse gas emissions to zero by 2050. This policy has the bipartisan support of both Australia's major political parties.

1. As interpreted on Slides 20 and 28 based on the GenCost25 Draft discussion on page 63.

Government policies are driving the transition of the Australian electricity industry from reliance on predominantly dispatchable, base-load, coal-fired power to VRE sources such as wind and solar, supported by peaking and Storage technologies and transmission.

The major issue concerning all stakeholders (including politicians, electricity industry participants, large and domestic consumers) is the impact of this transition on the cost and reliability of Australia's electricity supply.

Highly pertinent to this issue are the findings of the various CSIRO GenCost reports including GenCost25 Draft. Indeed, as the CSIRO states in the current and previous drafts: *"Current and projected electricity generation and storage technology costs are a necessary and highly impactful input into electricity market modelling studies"*. (Page 13).

Such market modelling studies are required by governments and regulators to assess alternative policies and regulations. The findings also influence public debate on a decarbonised energy economy. In this context, Draft GenCost25 has a critical role to inform policy makers and the public of the cost trade-offs of replacing fossil-fueled technologies with VRE and Firming technologies while maintaining system reliability.

On the issue of GenCots25 Draft, the CSIRO informed the media that its major conclusion was: "*The draft report found renewables continue to have the lowest cost range of any new-build electricity generation technology, for the seventh year in a row.*" In the release, CSIRO's Director of Energy, Dr Dietmar Tourbier, said: "*GenCost provides objective cost benchmarks using the best available and verifiable data. … GenCost's annual update delivers data-based forecasts that support informed decision making across energy sector …*" (CSIRO Media Release).

Simultaneously, Federal Ministers Bowen and Husic immediately issued a joint media release entitled "*Experts agree: Nuclear only getting more expensive, slower for Australia's energy needs*" (Fed24) which stated:

"*CSIRO and AEMO have specifically considered the claims of the Liberal Party about the life of nuclear reactors and capacity factors. The claims that these two things make nuclear cheaper have been clearly and emphatically rejected. … Renewables remain the cheapest new-build electricity generation in Australia to 2050, both as standalone assets and when also accounting for the required storage, transmission and firming.*"

These comments were in response to the release of two independent FE reports which concluded that the Coalition's nuclear-based energy policy was significantly cheaper than the Government's VRE-based energy policy (see Slide 11).

The associated Liberal Party media release stated: "*Labor's energy plan has been exposed as a $642 billion disaster in the making, with costs that are five times higher than what Labor has claimed. … Australians deserve to know the truth behind Labor's hidden costs and the impact it will have on energy bills and the economy.*" (Lib24).

Response to GenCost25 Draft Results (cont.)

Thus, the CSIRO, as a taxpayer-funded body, has now placed itself in the very difficult position as the most prominent source of expert advice supporting the Federal Government's energy policy based on firmed VRE generation technology being the lowest cost option. This advice has been challenged by an independent, energy industry expert that concludes that the Liberal National Party energy policy, based on the development of dispatachable nuclear generation technology, is significantly lower cost than the Federal Government's policy.

A major admission in GenCost25 Draft is that its LCOE methodology "… *is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance.* (Page 57). Indeed, the LCOE methodology is "... *designed to annualise all project costs into a single year. It is not well suited to costing a progression of projects over multiple years. Multi-year investment problems can be studied more appropriately in intertemporal electricity system models.*" (Page 61).

Significantly, the FE reports are based on sophisticated, more realistic and appropriate, intertemporal electricity system modelling.

Clearly, both conclusions cannot be correct.

Late last year, FE released two independent reports, prepared at FE's expense:

- The first report (**Frontier 1**) , released on 15 November 2024, estimated the cost of the Federal Government's energy policy of achieving NZ2050 through firmed VRE technologies. The report closely replicated the ISP24 projections of AEMO's ISP24, using similar assumptions. The purpose of Frontier 1 was to form a base case against which to assess the relative cost of adding nuclear generation to Australia. It was also designed to improve the debate on the potential introduction of nuclear generation in Australia.
- The second report (**Frontier 2**), released on 13 December 2024, estimated the cost of the Federal Coalition's energy policy of achieving NZ2050 by introducing nuclear generation capacity and displacing VRE generation capacity.

Frontier 2 concluded that the introduction of nuclear generation would be significantly cheaper than the Federal Government's policy as summarised in Table 10 (page 44) which is reproduced as Table 2.

Table 2: Generation, network and total system costs – NPV $ billion (2025 to 2051)

Scenario		Generation	Transmission	Total
Step Change	AEMO Base Case	190	35	225
	Nuclear Alternative	142	21	163
	Difference	48	14	62
Progressive	AEMO Base Case	148	17	166
	Nuclear Alternative	116	8	124
	Difference	32	9	42

The major conclusion is that the nuclear alternative scenario is projected to be significantly less expensive than the base case under both the Step Change and Progressive Scenarios. Accompanying the release of Frontier 2, FE noted the erroneous comparison of the cost of VRE generation plus Firming generation to the costs of nuclear generation (FE Insight). This comparison failed to account for:

- The fact that much more VRE capacity is required to produce the same amount of electricity compared to a nuclear power station and the requirement to store surplus VRE electricity from renewable sources as well as the back-up generation.
- The amount of investment required to connect renewable generators located in areas where presently there is either no, or inadequate, transmission network capacity.

Estimated Standalone LCOEs

CSIRO is yet to respond to serious issues raised last year regarding assumed CFs

ARDPL24 set out a detailed analysis of several major issues with assumed wind capacity factors (**CFs**). (See Appendix 2 for the relevant Slides from ARDPL24.) The conclusions from this analysis were as follows:

"*In GenCost24 Final, CSIRO needs to address the following very serious issues:*

- *The provision of evidence of the technological advancements that raise*[1] *(typographical error corrected) wind CFs.*
- *An explanation of the lack of balance between the setting of the low and high range CF assumptions.*
- *An explanation of the relationship observed between the assumed increasing CF assumptions and assumed decreasing real, unit wind capital costs.*
- *The use of much lower CFs for modelling than used to calculate LCOEs.*" (Slides 11 – 15)

The CSIRO's response was to include the following footnote: *"Appendix D of the GenCost 202-23: Final report provided a discussion of historical capacity factors upon which the data in this report is based.*" (Footnote 36, Page 67).

This footnote is repeated in GenCost25 Draft. (Footnote 30, Page 60). The problem is that many of the serious issues raised with respect to the assumed wind CFs were justified in Appendix D of the GenCost 2022-23: Final report.

That is, referring to the initial Appendix does not address the issues raised in respect of **THAT** Appendix.

Given the importance of the CF assumptions in determining the Standalone LCOEs, the CSIRO needs to provide a clear response to these issues in GenCost25 Final.

This Submission uses the actual CFs for wind and Solar PV LS for FY24 and the projected CFs for FY30 from the ISP24.

Update on these issues

- Evidence of the technological advancements that raise wind CFs?

To be clear, this question was in response to the CSIRO statement in GenCost 2022-23: "*The capacity factor range assigned to new build technologies are designed to be higher than the historical range. This is based on the view that new build technologies **may** include some technical advancements on their historical predecessors which mean they do not enter at the low range.*" (Page 51, emphasis added). The question does not relate to whether newer turbines are more efficient at converting wind energy. The question is whether more wind is passing over the blades of the newly built turbines. As this organisation has argued previously, on the assumption that the better VRE sites have been taken first, it is reasonable to assume that CFs for new-build VRE technologies will be lower than the CFs currently being achieved, notwithstanding improved turbines.

Of relevance, the data analysis of Australian wind farms presented in WattClarityNOV23 which concludes: "*There is no conclusive evidence that newer wind projects are delivering higher capacity factors across the NEM.*" (See Appendix 3 for a detailed review of this analysis.)

Assumed VRE capacity factors significantly exceed current observations (cont.)

- Evidence of current NEM CFs:
  - "*The average capacity factor or output of all Victorian wind farms during forecast Victorian USE periods is between 8-33% of their maximum output across the different reference years.*" (ESOO24, page 93).
  - "*Over the eight days from 20-27 May 2024 the capacity factor for the NE MVRE averaged 14 per cent. This is well below the 2023/24 annual capacity factor implicit in the Australian Energy Market Operator's 2024 Integrated System Plan (ISP) of 25 per cent.* " (AEC24).
  - "*Quarterly volume-weighted available capacity factors at established windfarms increased, with NEM-wide capacity factors averaging 39.5% in Q3 2024, up from just 25.3% in Q2 2024, and 34.4% in Q3 2023.*" (QED324, page 34).
  - "*… if the intent (sic) the CSIRO assumptions were to provide LCOE estimates for wind farm costs (feeding into the GenCost report), then their assumptions of >40% Capacity Factor for onshore wind would seem to be* ***overly optimistic****…*" (WattClaritySEP23).

Inconsistent treatment of Wind and Nuclear high range (low assumptions) CFs

Nuclear – 89%

"*GenCost agrees that high capacity factors of around 90% are achievable for nuclear generation. However, a prudent investor (government or private) must prepare for all plausible eventualities. The fact is that the global average capacity factor for nuclear generation is 80% and 10% of nuclear generation is operating at below 60%. This is because circumstances vary widely between countries and even within a country there is a merit order for generation dispatch. On international data alone, the proposition of only considering a 93% capacity factor is not supported by the evidence*". (GenCost25 Draft, page ix).

In summary, the nuclear CF is set below technically achievable levels because of risk aversion of the "prudent investor" must prepare for all "plausible eventualities".

Onshore wind – 48%

"*The capacity factor range assigned to new build technologies is based on a formula which uses the ten-year average capacity factors. For the high range, we use the high range of historically achieved capacity factors*". (GenCost25 Draft, page ix).

In summary, the onshore wind CF is set at the highest historical maximum outcome of 48% which occurred in 2018. Where has the "prudent investor" gone and where is the preparation for "plausible eventualities"? This is an unreasonable approach. Ironically, CSIRO refers to this assumption as "plausible".

While dispatachable nuclear plants are capable of sustaining an 89% CFs (or higher), intermittent Australia onshore windfarms cannot sustain a 48% CF. From experience, investment analysis of wind farms project base revenue forecast on the lower-than-average CFs; i.e., a "prudent" approach. At the average FY24 NEM CF of 26%, an investor in a wind farm assuming a 48% CF would have missed the projected generation and revenue targets by over 85%.

Assumed baseload capacity factors significantly less than technical capability

GenCost25 Draft assumes a 53% - 89% CF range for fossil-fuel and Nuclear LS baseload plants based on the CFs achieved recently by coal plants in the NEM that are significantly lower than the technical capabilities of new-build plant. This has the effect of significantly increasing the estimated LCOEs above those achievable when operating those plants at their technical capabilities.

The GenCost Methodology uses recent market history for setting the CFs for baseload plant that assumes that these plants will be unable to operate at their technical capability due to the preferences and subsidies given to VRE generators. Under this methodology, the proposition that integrated VRE is the lowest cost, new generation technology is impossible to disprove – effectively unfalsifiable. That is, as subsidised solar and wind generation increases, the CFs of baseload technologies reduce which makes them relatively more expensive, thus justifying the even greater use of solar and wind, putting aside the cost of the additional support for this capacity.

This organisation has consistently argued that this is a flawed method of developing the LCOEs so that the consequent GenCost results are of little value to policy makers and stakeholders.

Thus, the CSIRO's GenCost25 Final needs to apply the CFs for fossil-fuel and nuclear baseload technologies based on the technical capabilities of new-build plant and leave it to policy makers and other stakeholders to determine the desired policy settings.

This Submission uses a 93% CF for fossil-fuel and Nuclear LS baseload plants using AEMO data on planned and forced outage rates.

Failure to take account of connection costs and marginal loss factors in LCOE calculations

Appendix D.4.4 (page 99) sets out 12 costs factors excluded from the LCOE calculations. GenCost25 Draft states:

"*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).*" (Page 99). Two of the excluded factors (**Excluded Factors**) are connection costs and marginal loss factors **(MLFs**)**.**

This is organisation has provided quantitative evidence of the impact of including the Factors on the LCOEs on three occasions – the EPIA Paper, ARDL23 and ARDPL24.

The EPIA Paper (2022) raised the issue of the Excluded Factors and concluded:

"*The wind and large-scale solar estimated PV LCOEs increase significantly compared with the results reported in GenCost22. A major reason for this outcome is the generally higher ISP22 capital cost assumptions and the lower CFs combined with the addition of the connection costs and MLFs.*" (Page 22).

The CSIRO Response stated:

"*It is true that the standard formula for levelised cost of electricity does not include connection costs and marginal loss factors. However, when GenCost models the integration costs of renewables GenCost does include connection costs and partially consider losses.* (Page 9).

Thus, the CSIRO has received quantitative evidence that the impact on the LCOEs of the Excluded Factors is significant.

Further, the CSIRO Response stated that the Exclude Factors were included in GenCost 22 Final (at least partially). If so, why are they now excluded?

For absence of doubt, Table 3 sets out estimated impact of excluding connection costs and MLFs on VRE Standalone LCOEs relative to the fossil and nuclear fuel LCOEs using ISP24 input data.

Table 3: Impact of connection costs and MLFs on Standalone LCOEs

Year	Black coal	Gas CCGT	Nuclear LS	Solar PV LS	Wind onshore
FY24	2%	1%	3%	21%	14%
FY30	3%	2%	3%	25%	16%

Hopefully, the results in Table 3 is quantitative evidence that these Excluded Factors have a "large enough" impact.

Failure to take account of connection costs and marginal loss factors in LCOE calculations (cont.)

The CSIRO statement also demonstrates its disconnection from the market reality in the NEM in respect of the impact of the volatility of MLFs on investment in renewables. The release of the latest MLFs by AEMO in April 2024 drew the following reaction from the Clean Energy Investor Group[1]:

"*Given their calculation method, MLFs can change significantly each year, directly impacting generator revenue and increasing investor risk.*"

Further, at the same time, a representative of the Clean Energy Council stated[2]:

"*Major reductions in the MLF like this can cut a generator's revenue by 3% to 4%, from one year to the next. These kinds of changes increase uncertainty and increase the cost of building the volumes of new generation needed to decarbonise the power system.*"

1. Clean Energy Investor Group Media Release, 2 April, 2024."Marginal loss factor rules undermining urgent renewables growth, investors warn".

2. Linkedin post, Chrisitan Zurr, Director, Market, Grid and Investment Policy at Clean Energy Council

Amended estimated Standalone LCOEs

In line with the GenCost Purpose, the input data was used to derive the amended Standalone LCOE estimates by making the following changes to the following GenCost25 Draft assumptions:

- Black coal and Gas CCGT CF adjusted from 89% to 93% based on the technical capability provided in ISP22 and ISP24 respectively.
- Solar PV LS CF adjusted from GenCost25 Draft assumption to the average CFs from the ISP24 for the relevant year.
- Wind CF adjusted from GenCost25 Draft assumption to the average CFs from the ISP24 for the relevant year.
- Connection costs and MLFs were included based on AEMO data.

Table 4: Amended Standalone LCOEs estimates

	FY24 - Low		FY30 - Low	
Technology	**GenCost25 Draft Results**	**Amended Results**	**GenCost25 Draft Results**	**Amended Results**
Black coal	$102	$102	$92	$92
Gas CCGT	$128	$129	$85	$85
Nuclear LS	$155	$153	$150	$148
Solar PV LS	$43	$89	$35	$55
Wind	$70	$147	$56	$88

The amended Standalone LCOEs estimates for the low assumptions for FY24 and FY30 are set out in Table 4 and demonstrate the impact on the estimates of taking account of connection costs and MLFs and using VRE CF assumptions derived from the ISP24.

The impact on the dispatchable technologies is negligible in both FY24 and FY30 with the negative impact of introducing connection costs and MLFs being generally outweighed by the application of CFs based on technical capability.

The impact on VRE technologies is very significant. The results show that, by using the average CFs actually achieved in the relevant year rather than the CSIRO's high range assumptions (together with the addition of connection costs and MLFs), the estimated Standalone LCOEs are approximately 100% above the GenCost25 Draft results.

Estimated Firming Costs

GenCost25 Draft FY24 Firming Costs

GenCost25 Draft notes that: *"The integration costs are flat with increasing variable renewable share in the 2024 results. This is 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."* (Page 62).

"Integration costs to support renewables are estimated at $42/MWh to $48/MWh in 2024". (Page 64).

These statements are interpreted to mean that the $48/MWh relates to a 60% VRE Share in FY24 and the $42/MWh relates to a 90% VRE Share.

These unit **FY24 Firming Costs** have to support the Gencost25 Draft Pre-FY30 cost elements which are set out in Table 6-2: "*Committed investments by category included in the 2023 cost of integrating variable renewables*" (page 61), which is reproduced as Table 5.

Table 5: Gencost25 Draft Pre-FY30 cost elements (excluding Pre-FY30 Subsidies)

Element	**$ billion**
Transmission	15.9
Storage	22.9
Peaking gas	1.0
Total	**39.8**

In FY24 the NEM VRE Share was approximately 23% (excluding Rooftop PV). The additional VRE generation to take the VRE Share to 60% in 2024 multiplied by the $48/MWh integration cost to support VRE generation yields an annual cost that supports a capital value of approximately $40 billion. This is consistent with the $39.8 billion total Gencost25 Draft Pre-FY30 cost elements (excluding Pre-FY30 Subsidies) set out in Table 5.

Pre-FY30 Firming Cost elements

GenCost25 Draft identifies five major, pre-FY30 cost elements to Firm the VRE generation (**Pre-FY30 Firming Costs**) (page 61) as follows:

1. Existing "state renewable targets".
2. Snowy 2.0 and battery of the nation pumped hydro projects are assumed to be constructed before FY30.
3. Various transmission expansion projects (**TREX Projects**) already flagged by the "… the June 2022 ISP process to be necessary before FY30 (Table 6-2)." (Page 61).
4. NSW at Kurri Kurri gas-peaking plant assumed to have been constructed.
5. The NSW target for an additional 2GW of at least 8 hours duration storage.

Estimated Pre-FY30 Costs

Item 1 covers Federal and State Government-funded schemes (**Pre-FY30 Subsidies**) and is discussed in the next section.

Transmission

GenCost25 Draft values the TREX Projects at $15.9 billion in FY23 dollars (Table 6-2, page 61). This Table replicates Table 5-2 in GenCost22 Final (page 68).

The TREX Projects are listed in the June 2022 ISP (**ISP22**), Table 6 (page 67). The four transmission projects actionable before FY30 are: HumeLink, Sydney Ring, New England REZ Transmission Link and Marinus Link Cable 1.

This list of transmission projects and the associated cost estimates is two-years out of date.

Frontier 1 presents the results of a detailed analysis of transmission projects cost projections based on "… *upon publicly available information including from AEMO, the AER and project proponents*." (Page 34). As noted in Slide 11, FE were concerned about the cost to connect renewable generators located in areas where there is presently either no, or inadequate, transmission network capacity which could be avoided with the introduction of nuclear generation. Thus, FE wanted to obtain the best estimate of the cost of the transmission projects required to deliver NZ2050 using Firmed VRE technologies.

Pre-FY30 Firming Costs significantly understated (cont.)

Appendix 6 presents the list of the pre-FY30 transmission project costs developed by FE.

The mid-point cost estimate is $29 billion, with a range of $26 - $33 billion.

FE also noted:

"*NEM transmission projects are notorious for greatly exceeding their estimated costs. It is doubtful that the estimated upper bound of costs presented in Table 7 is, in fact, the upper bound.*" (Page 41).

This Submission uses $35 billion as the estimated cost of the pre-FY30 transmission projects needed to deliver VRE generation to the grid.

This is $19.1 billion higher than the $15.9 billion Gencost25 Draft Pre-FY30 transmission cost element included in Table 5.

In order to support the additional $19.1 billion estimated capital cost , the FY24 Firming Costs need to increase by 48% or $23/MWh for a 60% VRE Share and $20/MWh for a 90% VRE Share.

Pre-FY30 Subsidies

ARDPL24 noted the omission of the cost of government subsidies. This criticism was based on the following statement in the Draft GenCost24: "*In 2030, we project forward including all existing state renewable energy targets …*" (Page 57). This statement is repeated in Gencost25 Draft. (Page 60).

Appendix D.4.10 contains the following statement:

"*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.*" (Page 105)

First, ARDPL did not argue that the subsidies lowered the Standalone LCOE estimates but that they had been excluded from the pre-FY30 integration costs (page 3). That is, the subsidies were treated as an omission from the 2023 integration costs (page 19).

Consequently, the statement in Appendix D.4.10 does not address the issue this organisation raised.

Pre-FY30 Subsidies (cont.)

Secondly, the GenCost25 Draft responses raises several issues:

1. What is the purpose of the statement "… *forward including all existing state renewable energy targets*" if the associated subsidies have no impact on the cost of Firmed VRE. Interestingly, the following statement is made earlier in GenCost25 Draft: "*Victorian legislation creates are (sic) mandate for offshore wind generation, but this does not come into place until after 2030 and so is outside the scope of our analysis.*" (Page 60). How could such a policy affect the analysis if Government subsidies are excluded?
2. Further, if Firmed VRE technologies generate the lowest cost electricity, why are the subsidies needed?
3. Moreover, many of the subsidies, such as the Rewiring the Nation scheme, relate to the transmission of VRE generated electricity. Others, such as the various battery storage projects supported by the Australian Renewable Energy Agency (**ARENA**), relate to the Firming of VRE generated electricity. These subsidies are paid by taxpayers to the clear benefit of VRE projects.

Fossil fuel and hydro generation technologies do not receive such subsidies. Therefore, it is highly misleading to omit these subsidies when making comparisons between the cost of electricity from various generation technologies.

Valuation of the Pre-FY30 Subsidies

The following major government programmes subsidise large-scale VRE projects:

- ❑ Cost of the funds awarded to VRE projects under the existing government renewable targets (**Government Targets**).
- ❑ Cost of the funds awarded to VRE projects by the Clean Energy Finance Corporation (**CEFC**).
- ❑ Cost of the funds awarded to VRE projects by the ARENA.
- ❑ Cost incurred by the Clean Energy Regulator to administer the Renewable Energy Target.
- ❑ Managing electricity system security due to the growing VRE penetration.

CIS24 contains estimates of the cost of the CEFC and ARENA subsidies in FY23. ARDPL24 contained estimates of the costs of the other programmes in FY23.

The total costs of the subsidies divided by the electricity from VRE technologies in FY23 yields a unit cost of the subsidies of approximately $20/MWh.

This Submission uses $20/MWh as the estimated cost of the Pre-FY30 Subsidies.

Reliability of the projected FY30 electricity system - GenCost25 Draft compared with the ISP24

Chart 1: GenCost25 Draft and ISP24 projected generation technology mixes

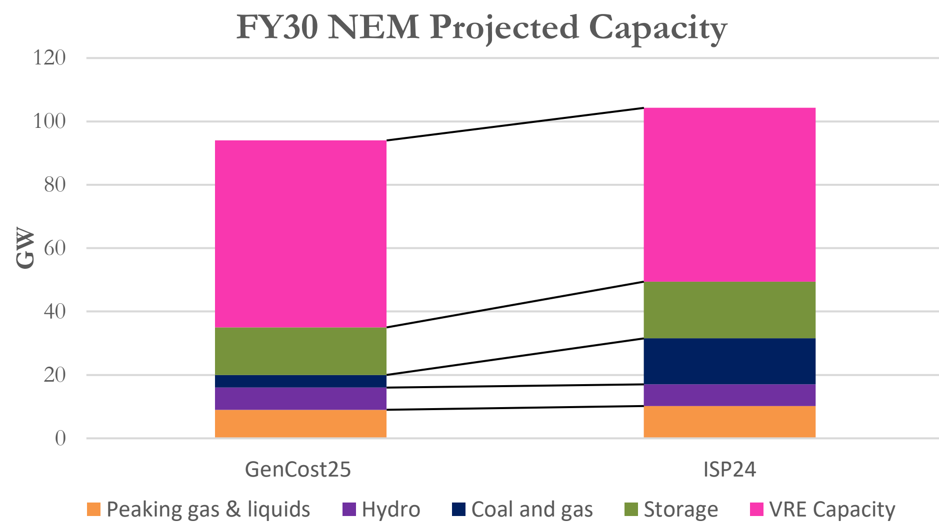


Chart 1 sets out the projected generation technology mixes from GenCost25 Draft (Figure 6.7, page 69[1]) and ISP24, excluding Rooftop PV. The GenCost25 Draft VRE capacity is approximately 59GW for a 90% VRE Share of generation. The ISP24 VRE capacity is approximately 55GW for a 65% VRE Share. Both technology mixes are projected to deliver the load reliably in FY30, excluding Rooftop PV. The GenCost25 Draft load is "lower" by an unknown amount[2] (page 62).

GenCost25 Draft projects significantly less dispatachable capacity (~35GW) in FY30 than the ISP24 (~49GW) to support a much higher VRE Share.

The dispatchable reserve margin (**DRM**) is the ratio of dispatchable capacity to maximum (or peak) demand and is a common measure of the security of the system to supply the load in the face of major disruptions. Historically, a minimum of 120% has been considered a safe margin for large systems, although the introduction of non-dispatchable, VRE generation technologies has increased this minimum margin.

The projected peak demand in FY30 of 37GW is taken from Figure 6.7.

GenCost25 Draft requires a projected DRM of 95% to provide a reliable system in FY30 with a 90% VRE Share. In marked contrast, the ISP24 requires a projected DRM of 134% with a 65% VRE Share to achieve the same outcome.

On this measure, notwithstanding the lower load, the GenCost25 Draft system appears significantly less reliable than the ISP24 system.

1. The data are drawn from Figure 6.7, page 69 by observation. The CSIRO should publish this data to allow a more detailed analysis of the plausibility of the GenCost25 Draft projections.
2. For the same reason, the CSIRO should publish this data so that a better analysis could be conducted

GenCost25 Draft's reliance on Storage to meet FY30 peak demand

It was noted in the previous Slide that the GenCos25 Draft FY30 system has a DRM of 95%. Thus, to meet the FY30 maximum demand, this system requires full Storages and some VRE generation. Table 6 reproduces Figure 6.7 (page 69)[1] which sets out the dispatchable, Firming capacity in FY30.

Table 6: Gencost25 Draft dispatchable capacity

Technology	GW
Peaking gas and liquids	9
Hydro	7
Coal and gas	4
Storage	15
Total	**35**

This capacity can be separated into **Firm Dispatchable Capacity** (Peaking gas and liquids, Hydro and Coal and gas) and Storage. Storage represents 43% of total Firming capacity compared with 36% for the ISP24 FY30 projected system.

The major issue is whether this maximum load of 37GW in FY30 can be delivered by approximately 20GW of Dispatchable Capacity, approximately 15GW of Storage capacity and approximately 59GW of VRE capacity.

The ISP24 projects the FY30 peak to occur in the early evening in winter. (Figure 8, page 28). At that time, there will be no solar generation which is 30% of the ISP24 VRE capacity. Applying this proportion to the GenCost25 Draft capacity leaves approximately 40GW of wind capacity. The wind CFs are lower in winter and can be less than 10% for several days during Weather Droughts (see Appendix 5). Further, Appendix 5 demonstrates that the minimum monthly aggregate wind CF in the NEM was effectively zero over several months in the last decade[2].

Thus, in approximate terms, to meet the peak demand would require all the 20MW of Firm Dispatchable Capacity and 15GW of Storage to be available plus at least 2GW of wind capacity; i.e., a wind CF at that time of 5%.

The ISP24 projects the FY30 system to contain 32MW of Firm Dispatchable Capacity and 18GW of Storage. Thus, in marked contrast to the GenCost25 Draft system, the ISP24 system can meet the peak with only 16% of the Storages full and place no reliance on wind generation.

On this measure, notwithstanding the lower load, the GenCost25 Draft system appears significantly less reliable than the ISP24 system.

1. Again, the CSIRO should publish this data to allow a more detailed analysis of the plausibility of the GenCost25 Draft projections.
2. In critiques of several GenCost reports, this organisation has drawn attention to the implications of Weather Droughts in assuming unrealistic VRE CFs. Appendix 5 reviews the impact of Weather Droughts on VRE CFs and demonstrates that the minimum monthly aggregate CF for wind was effectively zero in several months over the last decade so that no amount of VRE capacity could "deliver" any load in those periods.

Relevance of average VRE CFs

The average CF of VRE technologies is of virtually no relevance to the reliability of a technology mix to deliver the maximum load.

From various statements and charts in various GenCost25 reports, there could be confusion over the difference between the average CF over different time periods and the relevance of average CFs of dispatchable generators compared with intermittent, VRE generators.

First, GenCost22 Final made the following statement on this issue: "*Variable renewables have a low capacity factor, which means the full capacity is only generating for a fraction of the year (e.g., 20% to 40%).*" (Page 60).

The EPIA Paper noted that the first sentence is incorrect because *"… VRE technologies only operate at "full capacity" for a very few hours per year. Rather, these technologies have low annual* ***average*** *CFs in the 20% - 40% range*". (Page 15, emphasis added).

Without acknowledgement in the CSIRO Response, GenCost23 Final amended the sentence as follows: "*Variable renewables have a low capacity factor, which means their actual generation over the year expressed as a percentage of their potential generation as defined by their rated capacity, is low (e.g., 20% to 40%).*" Thus, there was confusion about how the average CFs of VRE technologies are accumulated and the usefulness of such averages.

Secondly, GenCost25 Draft repeats the following statement that has been in every GenCost report since GenCost22 Final:

"*The average capacity factor of coal dominated electricity supply in Australia is around 60%. As a result, to deliver the equivalent energy of coal-fired generation, the system needs to install around two times the capacity of variable renewables. If the system were to also build the equivalent capacity of storage, peaking and other flexible plant then the system now has around four times the capacity needed compared to a coal dominated system. For a number of reasons, this scale of capacity development is not necessary to replace coal.*". (Page 68).

The second sentence is only correct at an average VRE CF of 30% over the period. It is not correct in every dispatch period and so, for this reason, comparing the average CF for dispatchable plant with that of VRE capacity is not correct. This is implicitly acknowledged in the third sentence which refers to the dispatchable capacity required to support intermittent, VRE capacity. Sentence four prompts the question as to how much dispatchable capacity is required and the reliability of that capacity.

Thirdly, GenCost25 Draft states: "*Existing electricity systems have existing peaking and flexible generation. This reduces the amount of new capacity that needs to be built. This is true for coal generation or any other new capacity as it is for variable renewable generation. All new capacity relies on being supported by existing generation capacity to meet demand.*" (Page 68).

Non-dispatchable VRE capacity cannot "support" dispatchable capacity. In the NEM, VRE capacity has preferential dispatch and so, is generally operating in preference to dispatchable capacity. When the VRE generation falls, dispatchable increases to meet the load, not other VRE capacity.

1: In critiques of several GenCost reports, this organisation has drawn attention to the implications of Weather Droughts in assuming unrealistic VRE CFs. Appendix C review the impact of Weather Droughts on VRE CFs and demonstrates that the minimum monthly aggregate CF for wind was effectively zero in several months over the last decade so that no amount of VRE capacity could "deliver" any load in those periods.

GenCost25 Draft's reliance on Storage to meet peak demand (cont.)

How reliable are Storages?

From Slide 25, GenCost25 Draft requires 5% of VRE capacity, all Firming Dispatchable Capacity to be generating and the 15GW of Storages to be full to meet the peak demand in FY30.

GenCost25 Draft makes the following statement regarding the summer peak: "… *during a summer peaking event day, solar PV generation will have been high earlier in the day and consequently storages are relatively full and available to deliver into the evening peak period.*"(Page 68).

This is a very simplistic representation that assumes that Storages will refill regularly. However, this is not the case given the existence of Weather Droughts. Thus, sufficient Storage is required to ensure a reliable supply if the Storages fail to refill on a daily basis.

The CSIRO says that it deals with this "… *uncertainty in variable renewable production by modelling nine different weather years, 2011 to 2019.*" (Page 60).

Since GenCost21 Final, the CSIRO has modelled a reliable system under the **worst** observed outcome in the particular weather years.

CSIRO has never published the details of these nine weather years which is a very short period of time over which to measure weather risk. This short period does not meet the standards for infrastructure and land-use planning which look to significantly longer periods; e.g., a one in a 100-year event or a 1% chance of an event occurring in the next year.

Further, earlier CSIRO analysis based its estimates of the amount of Storage required to achieve a reliable system under conditions "**significantly worse**" than observed. The "significantly worse" conditions were derived by repeating the "worst" week observed in the observation period and repeating it for three continuous weeks. (See Appendix 4.)

Based on this and again notwithstanding the lower load, it is reasonable to conclude that the GenCost25 Draft system does not contain sufficient Storage to be confident, at a high level of probability, that the peak demand can be met.

This is supported by the negative GenCost25 Draft FY30 DRM compared with the ISP24 system which is also projecting a reliable system in FY30.

Thus, given the similar peak loads, both projected systems cannot be equally reliable.

Consequently, , the GenCost25 final report should either explain why the projected system is reliable with a DRM of 95% or significantly increase the DRM which will increase the cost of Firming the VRE capacity. This will increase the cost of Firmed VRE relative to the baseload technologies.

FY30 Firming Costs significantly understated

The previous Slides concluded that that the GenCost25 Draft FY30 DRM needs to be increased significantly to ensure a reliable projected system.

GenCost25 Draft notes that:

"Integration costs to support renewables are estimated at $20/MWh to $50/MWh in 2030". (Page 64).

This statement is interpreted to mean that the $20/MWh relates to a 60% VRE Share in FY30 and the $50/MWh relates to a 90% VRE Share. These are referred to as the FY30 Firming Costs.

Slide 24 noted that the projected GenCost25 Draft FY30 DRM was 95% DRM compared with a DRM of 134% in the ISP24. Approximately an additional 14GW of dispatachable capacity is needed to achieve a GenCost25 Draft FY30 DRM of 134% and give a greater prospect that the amended GenCost25 Draft can supply the peak demand reliably.

As an indicator of the potential cost impact of increasing the DRM, it is assumed that the additional 14GW of dispatchable capacity is Storage.

Based on the share of the Firming costs set out in Figure 6.7 (page 69[1]) accounted for by Storage and the GenCost25 Draft estimated cost of Storage (page 64), the FY30 Firming Costs would increase by $10/MWh[2].

1: Again, the CSIRO should publish the data of this Figure to allow a more accurate assessment of the projections.

2. This amendment applies to both the 60% and 90% VRE Shares as the peak demand is unchanged.

Omitted FY30 Subsidies

Draft GenCost25 states: "*In 2030, we project forward including all existing state renewable energy targets …*" (Page 60).

However, as with the FY24 costs, the FY30 costs omit the costs (**FY30 Subsidies**) of the major government programmes that subsidise large-scale VRE projects.

In addition to the existing programmes relevant to FY24 set out on Slide 23, there is the subsidy element of:

- The additional cost of the expansion to Capacity Investment Scheme announced by the Federal Government in November 2023 to target 23GW of renewable capacity ($52 billion) and an additional 9GW of dispatchable capacity ($13 billion).
- The Rewiring the Nation programme to provide $20 billion to upgrade transmission infrastructure to lower the cost of delivering VRE to the major load centres. This fund has invested in some of the transmission infrastructure listed in Frontier 1 so there may be some double counting if the total value of the fund is included in the FY30 Subsidies.
- The $2 billion Green Aluminium Production Credit, available from 2028–29, to Australia's aluminium smelters to transition to VRE.

There also continues to be pressure from various sectors of the energy industry for more Government financial support to the investment in VRE (see CEIG25).

Given the requirement to date to subsidise VRE generation and Firming costs, the open-ended nature of the most recent support programmes outlined above and the ongoing pressure from the VRE industry for Government support, it is prudent to apply the same allowance for the FY30 Subsidies as the Pre-FY30 Subsidies, $20/MWh.

Amended FY24 and FY30 Firming Costs

This Submission has identified a major understatement and omission from the FY24 Firming Costs provided in GenCost25 Draft as follows:

1. understatement of the cost of transmission; and
2. omission of the Pre-FY30 Subsidies.

The Submission has also identified a major understatement and omission from the FY30 Firming Costs as follows:

1. understatement of the cost of Storage; and
2. omission of the FY30 Subsidies.

The results of amending the FY24 and FY30 Firming Costs provided in GenCost25 Draft are set out in Table 7.

Table 7: Amended FY24 and FY30 Firming Costs

Firming Costs - $/MWh	FY24		FY30	
VRE Share	**60%**	**90%**	**60%**	**90%**
GenCost25 Draft	$48	$42	$20	$50
Understated transmission cost	$23	$20	$0	$0
Omitted Pre-FY30 Subsidies	$20	$20	$0	$0
Understated Storage cost	$0	$0	$10	$10
Omitted FY30 Subsidies	$0	$0	$20	$20
Total	**$91**	**$82**	**$50**	**$80**

These Amended Firming Costs significantly exceed the GenCost25 Draft estimates and are used in the next Slide to amend the GenCost25 Draft Firmed LCOEs.

Amended Firmed LCOEs

Table 8 sets out the sum of the Amended Standalone LCOEs (Table 4, Slide 18) and the Amended Firming Costs (Table 7, Slide 30) for the five generation technologies investigated.

Table 8: Amended FY24 and FY30 Firmed LCOEs

FY$/MWh	FY24 - Low		FY30 - Low	
Technology	**GenCost25 Draft Results**	**Amended Results**	**GenCost25 Draft Results**	**Amended Results**
Black coal	$102	$102	$92	$92
Gas CCGT	$128	$129	$85	$85
Nuclear LS	$155	$153	$150	$148
Solar PV LS	$43	$89	$35	$55
Wind	$70	$147	$56	$88
Solar PV LS - 60% VRE Share	$91	$180	$55	$105
Wind - 60% VRE Share	$118	$238	$76	$138
Solar PV LS - 90% VRE Share	$85	$171	$85	$135
Wind - 90% VRE Share	$112	$229	$106	$168

When the GenCost25 Draft's estimated LCOEs are amended for several major understatements and omissions, the resultant amended LCOEs of VRE technologies are significantly higher than the estimated LCOEs of black coal, gas CCGT and Nuclear LS in FY24 and FY30.

These results clearly refute CSIRO's claim: "*The cost range for variable renewables with integration costs is the lowest of all new-build technology capable of supplying reliable electricity in 2024 and 2030.*" (Slide 8).

Significantly, the results also support the FE conclusion that the nuclear alternative scenario is projected to be significantly less expensive than the ISP24 base case reliant on Firmed VRE (Slide 11).

These results also support FE's warnings about the need to account for the cost of Storage and transmission in projecting the cost of Firmed VRE generation for comparison with the costs of nuclear generation (or any other dispatchable generation technology).

Other Issues

Does the addition of VRE technologies put downward pressure on retail electricity prices?

GenCost25 Draft states that: "*There is no guarantee that renewables or any other new entrant technology will maintain downward pressure on prices. If capacity is retired faster than it is rebuilt, then prices will increase again regardless of the cost of new entrant capacity*." (Page 105).

Thus, CSIRO claims that the introduction of VRE generation puts downward pressure on prices. Whether this downward pressure is maintained depends on subsequent demand and supply developments.

Chart 2: VRE penetration and real Australian consumer electricity prices

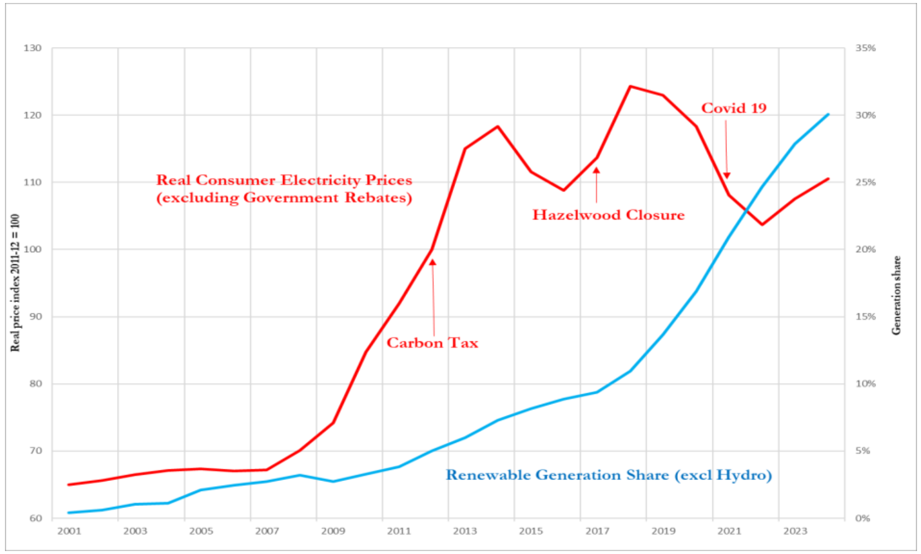


Chart 2 shows that the share of total electricity generation attributable to VRE technologies (excluding hydro, including Rooftop PV) has risen dramatically since 2009. This increase in the VRE Share has coincided with a significant increase in real, retail consumer electricity prices.

The increase in VRE Share has largely been achieved by reducing coal-fired generation's share of total generation from approximately 85% in FY09 to approximately 56% in FY24. The major drivers of this reduction in the coal-fired generation share are the dispatch preference given to renewables and the Pre-FY24 Subsidies (see Slide 22).

This Chart is not consistent with the CSIRO argument that the entrance of VRE generation technologies puts downward pressure on electricity prices.

1: Consumer price data is sourced from Australian Bureau of Statistics, Catalogue 6401.0 - Consumer Price Index, Australia and the electricity generation data is sourced from the Department of Industry, Science, Energy and Resources, Australian Energy Statistics.

Rather, the Chart is consistent with the proposition outlined in this Submission that Firmed VRE generation technologies are extremely expensive because of the need to collect the VRE electricity from remote regions and Firm it to ensure a reliable electricity supply. The Subsidies required to force VRE technology into the system are also reflected in Real Consumer Electricity Prices.

Another effect of the reduction in the coal-fired generation share is that coal generators are setting the wholesale price less frequently.

Chart 3: NEM price-setting dynamics by fuel

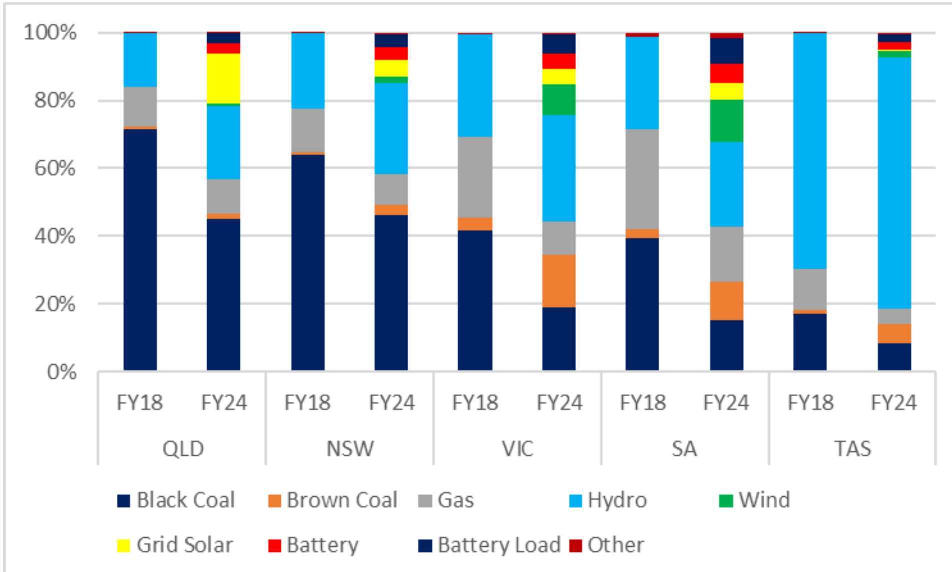


Chart 3 sets out the NEM price-setting dynamics by fuel derived from various issues of AEMO's Quarterly Energy Dynamics (**QED**) for FY18 through FY24.

The Chart shows that in FY18, NEM prices were set predominantly by coal in all regions except Tasmania. The proportion of the time coal set the prices ranged from 73% in QLD, 65% in NSW, 46% in VIC and 42% in SA. QED notes that coal generators in another region may set the price in some periods. The next dominant price setting fuel was hydro, with gas setting the price in SA 30% of the time, VIC 24%, NSW 13% and QLD 12%.

In FY24, the price-setting role of coal had diminished significantly to 49% in NSW, 46% in QLD, 34% in VIC and 26% in SA with hydro setting the price the next most often. The role of gas in setting the price diminished in all regions, particularly SA and VIC.

The loss of the lower marginal cost, dispatchable generators setting the wholesale price has coincided with upward pressure on wholesale prices.

Linkage of LCOEs to electricity generation capacity investment signals.

GenCost25 Draft posed the question: "*If GenCost shows renewables are cheaper, why are electricity prices higher in Australia and in countries transitioning to renewables*?" (Appendix D.4.17, Page 105). The reference to "electricity prices" is clearly in the context of retail electricity prices.

The CSIRO responded with the following statement: the LCOE is "… *an indicator of the electricity price needed to encourage new investment, but it does not control the electricity price*." (Appendix D.4.17, Page 108).

In the experience of this organisation, the investment signal to new dispatachable generation capacity is either the projection of the wholesale (spot) price of electricity or a power purchase agreement from a creditworthy offtaker. For VRE generation technologies, these market-based price signals are augmented by the Subsidies available.

That is, contrary to the CSIRO's view, retail electricity prices have very little relationship to the signals for new generation investment.

Linkage of LCOEs to retail electricity prices

Based on the average of the costs identified by IEEFA, the five major cost components of an Australian retail electricity bill (**Retail Bill**) are set out in Table 9.

Table 9: Cost Components of a Retail Bill

Cost Component	%
Wholesale cost	32%
Network cost (distribution (~80%) and transmission (~20%))	43%
Retail cost	13%
Environmental cost	7%
Retail margin	6%
Total	**100%**

The LCOEs have very little relationship to the components of a Retail Bill. It might be argued that the LCOEs impact the Wholesale cost which reflect the costs incurred by retailers to source power from the pool either at spot prices or at contracted prices. That is, this component of the Bill is based on electricity actually generated and delivered.

Linkage of LCOEs to retail electricity prices (cont.)

As demonstrated in this Submission, the LCOEs are totally unrelated to electricity actually generated and delivered.

Rather, the LCOE calculations assume access to the existing generation plant is “free”, assume average CFs that have never been achieved and omit the impact of MLFs and connection costs which all flow through to a Retail Bill

Thus, the LCOEs cannot be expected to have a strong relationship to a Retail Bill.

This begs the question as to the relevance of the GenCost25 Draft conclusions based on LCOEs to retail electricity prices and the broader Australian energy policy debate.

Treatment of Pre-FY30 Firming Costs

Feedback misunderstood

The first major issue raised in this ARDL23 under the heading "**GenCost integration results of little relevance and poorly explained"** (Slide 3) was as follows:

*"The GenCost methodology only applies to the cost of integrating additional VRE capacity in FY2030 ABOVE the 54% VRE generation share (**VRE Share**) projected in the business as usual (**BAU**) case in FY2030. That is, the methodology DOES NOT measure the cost of integrating additional VRE capacity above the current level of approximately 20% in FY2022 to approach 54% in FY2030."*

"Thus, the GenCost results are of little relevance to the major issue TODAY - what is the integration cost to maintain a reliable system while increasing the VRE Share from the current level to 54% by FY2030?"

Thus, the feedback was to include **ALL** the pre-FY30 integration costs in **FY30**. This was obvious from the diagram in Slide 4 which is reproduced as Slide 39.

GenCost24 Final responded by including *"… variable renewable integration costs for 2023 which include committed and under construction pre-2030 storage and transmission projects."* (Page x). Thus, rather than include the costs in FY30, they were included in FY23. This method is adopted in GenCost25 Draft by including some of the pre-FY30 costs in FY24. On Slide 21, the pre-FY30 costs are defined as **Pre-FY30 Firming Costs.**

Relevance of the FY24 LCOEs

In order to include the Pre-FY30 Firming Costs in FY24, the CSIRO abstracts: "… *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 methodology is designed to annualise all project costs into a single year*." (Page 61).

What is the relevance of the FY24 LCOEs that include all the Pre-FY30 Firming Costs?

By the time GenCost25 Draft was released there was actual FY24 data on the VRE Share of generation (~23% excluding Hydro and Rooftop PV) and capacity factors (wind ~26% and Solar PV LS ~19%).

The low range assumed FY24 capacity factor for wind is 48% and for Solar PV LS is 32%? These assumptions are 70% to 85% higher than the actual FY24 average farm capacity factors. Nevertheless, the CSIRO assumes that the thousands of MW of new-build wind capacity required to approximately double and triple the actual FY24 wind generation share will operate at more than 80% of the average capacity factor actually achieved in FY24 by operating wind farms.

This is contrary to the data about the capacity factor achieved by new wind farms, totally unrealistic and clearly an abstraction from reality.

The CSIRO describes these assumption as "plausible".

Do not "sink" the Pre-FY30 Firming Costs

A more realistic approach would be to include all the Pre-FY30 Firming Costs in FY24 as recommended in ARDL23 and as depicted in the diagram in Slide 39. Since all of these Costs will have been incurred by FY30, no abstraction from reality is required.

To give an indication of the impact of this approach, Table 10 first summarises the current GenCost approach of including all the Pre-FY30 Firming Costs in FY24 based on actual outcome in FY24 and the ISP24 projections for FY30.

Table 10: Including all the Pre-FY30 Firming Costs in FY24

Timing	Firming Cost - $/MWh	VRE Generation - PWh	Total Cost - $ billion
FY24	$0.00	43	0.0
Additional generation to achieve 90% VRE Share in FY24	$42.00	127	5,318
Additional generation to achieve 90% VRE Share in FY30	$50.00	45	2,260
Total generation to achieve 90% VRE Share in FY30		**215**	**7,578**

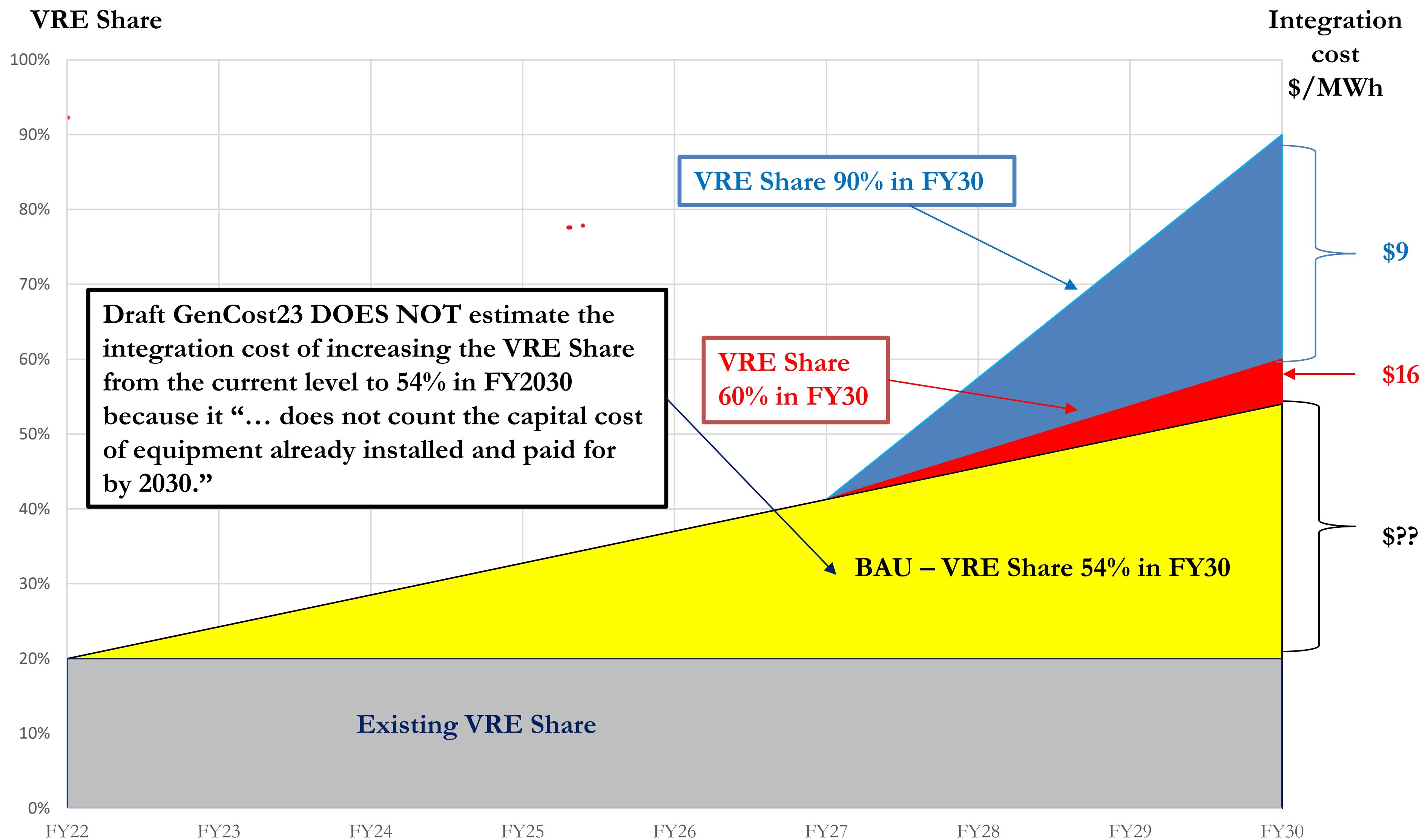
Table 11 gives an indication of the impact of including all the Pre-FY30 Firming Costs in FY30.

Table 11: Including all the Pre-FY30 Firming Costs in FY30

Timing	Firming Cost - $/MWh	VRE Generation - PWh	Total Cost - $ billion
FY24	$0.00	43	0.0
Additional generation to achieve 90% VRE Share in FY30	$44.10	172	7,578
Total generation to achieve 90% VRE Share in FY30		**215**	**7,578**

Based on the GenCost25 Draft, approximately $44/MWh is required to Firm VRE generation in FY30 for a 90% VRE Share.

As noted earlier in this Submission, the GenCost25 Draft Firming Costs are materially understated due to the unrealistic assumptions and the understatement and omission of major costs. If the amended Firming costs are applied (see Slide 30), approximately $82/MWh is required to Firm VRE generation in FY30 for a 90% VRE Share.


VRE Share
Integration cost $/MWh
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
VRE Share 90% in FY30
$9
VRE Share 60% in FY30
$16
Draft GenCost23 DOES NOT estimate the integration cost of increasing the VRE Share from the current level to 54% in FY2030 because it "… does not count the capital cost of equipment already installed and paid for by 2030."
BAU – VRE Share 54% in FY30
$??
Existing VRE Share
FY22
FY23
FY24
FY25
FY26
FY27
FY28
FY29
FY30

Conclusion

See Executive Summary – Slides 3 -5.

Appendix 1: Document References

Title	Publication date	Abbreviation
ARDL Submission on Consultation Draft GenCost 2022-23	February 2023	ARDL23
ARDPL Submission on Consultation Draft GenCost 2023-24	February 2024	ARDPL24
Australian Energy Council, Dunkelflaute writ large - May 2024?	August 2024	AEC24
Australian Electricity Market Operator, Electricity Statement of Opportunities	August 2024	ESOO24
Australian Electricity Market Operator, Integrated System Plan, 2022	June 2022	ISP22
Australian Electricity Market Operator, Integrated System Plan, 2022	June 2024	ISP24
Australian Electricity Market Operator, Quarterly Energy Dynamics, Q3 2024	October 2024	QED324
Centre for Independent Studies, Counting the Cost: Subsidies for Renewable Energy	June 2024	CIS24
Clean Energy Investment Group, Australia's Productivity Pitch: Investing in cheaper, cleaner energy and the net zero transformation	January 2025	CEIG25
CSIRO, GenCost 2018, Updated projections of electricity generation technology costs	December 2018	GenCost18 Final
CSIRO, GenCost 2019-20, Final report	May 2020	GenCost20 Final
CSIRO, GenCost 2020-21, Final report	June 2021	GenCost21 Final
CSIRO, GenCost 2021-22, Final report	July 2022	GenCost22 Final
CSIRO, GenCost 2022-23, Final report	July 2023	GenCost23 Final
CSIRO, GenCost 2023-24, Final report	July 2024	GenCost24 Final
CSIRO, GenCost 2024-25, Consultation draft	December 2024	GenCost25 Draft
CSIRO, Response to Energy Policy Institute of Australia paper, 3/2022	November 2022	CSIRO Response
CSIRO, Low Emissions Technology Roadmap	June 2017	CSIRO Roadmap
CSIRO, Media Release	December 2024	CSIRO Medial Release
Energy Policy Institute of Australia paper 3/2022, Future Australian Electricity Generation Costs - A Review of CSIRO's GenCost 2021-22 Report	September 2022	EPIA Paper
Federal Government, Joint media release - Experts agree: Nuclear only getting more expensive, slower for Australia's energy needs	December 2024	Fed24
Frontier Economics INSIGHT, Economic analysis of including nuclear power in the NEM	December 2023	FE Insight

Appendix 1: Document References (cont.)

Title	Publication date	Abbreviation
Frontier Economics, Report 1- Developing a base case to assess the relative costs of nuclear power in the NEM	November 2023	Frontier 1
Frontier Economics, Report 2 - Economic analysis of including nuclear power in the NEM	November 2023	Frontier 2
Independent Engineers and Scientists, Response to Draft AEMO Integrated System Plan	February 2022	Independent E&S
Institute for Energy Economics and Financial Analysis, Nuclear in Australia would increase household power bills	September 2024	IEEFA
Liberal Party, The real cost of Labor's energy plan revealed	November 2024	Lib24
WattClarity, Extended long-term trend of wind production statistics (to the end of August 2023)	September 2023	WattClaritySEP23
WattClarity, Bigger or better: Are newer wind farms outperforming older ones?	November 2023	WattClarityNOV23

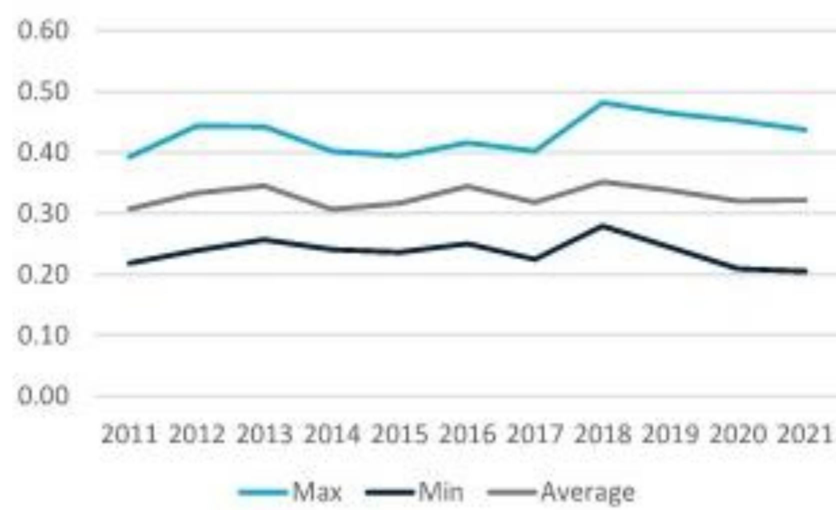
Appendix 2 – Slides from ARDPL24

Assumed VRE capacity factors significantly exceed current observations

There are several major issues with assumed wind capacity factors (**CFs**).

First, Draft GenCost23 Submission criticised the assumed CF range for wind in 2030 of 35% - 46%[1] as not related to market reality given even the minimum assumptions exceed the CFs currently being achieved. Thus, it was difficult to accept that such assumptions are "plausible". The assumed CF range for wind in 2022 was 35% - 44%.

The GenCost23 Final response to the criticism was to change the 2022 and 2030 ranges to 29% - 48% - a 9% increase in the high range, thus moving further away from market reality. CSIRO justified its changes to the wind CFs as follows: "*The capacity factor range assigned to new build technologies are designed to be higher than the historical range. This is based on the view that new build technologies* ***may*** *include some technical advancements on their historical predecessors which mean they do not enter at the low range. Consequently, their low range capacity factor assumption is closer to the average capacity factor rather than the worst case. Specifically, we assume the low range value is 5% below the average. The high range assumption is that it equals the historical high range.*" (Page 51, emphasis added).



The preceding chart is reproduced from GenCost23 Final, Apx Figure D.1, Historical maximum, minimum and average capacity factors for existing NEM wind generation (page 80).

1: The 2030 wind CF range had been 35% - 46% for GenCost18 and 46% for GenCost20 Final and GenCost21 Final.

Assumed VRE capacity factors significantly exceed current observations (cont.)

From the preceding chart, GenCost23 acknowledged that the *"… capacity factor for wind has been relative (sic) steady …"* (Page 80).

Thus, CSIRO's historical wind data shows that no such "technical advancements" have occurred.

Secondly, the low range CF assumption is set at 5% below the historical average of $33/MWh while the high range assumption is set at the historical high range.

- The historical high range CF for wind is 48% which occurred in 2018 and has declined ever since.

If the approach of linking the CF range to the historical average is to be applied, it should be applied even-handedly which would result in the the high range CF assumption being set at 5% above the historical average, yielding a 38% high range wind CF.

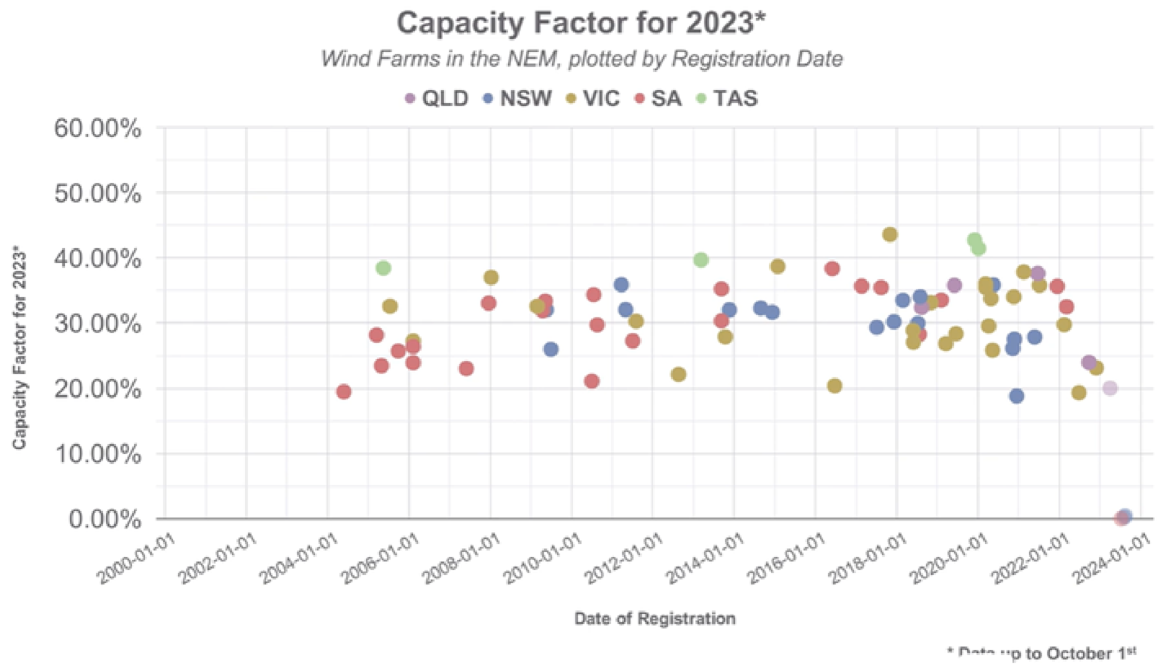
Thirdly, the increases in the high range CF assumption has a material impact on the projected LCOE for integrated wind. For example, the impact of these assumptions on the projected 2023 cost of integrated wind for the high range assumption is as follows:

High Range CF Assumption	**33%**	**38%**	**44%**	**48%**
	Average	**Average +5%**	**2018-22**	**Draft GenCost24**
Standalone	$96	$83	$69	$66
60% VRE Share	$137	$124	$110	$107
90% VRE Share	$130	$117	$103	$100

The results show that the assumed increases in the high range CF have served to lower the projected wind LCOEs materially.

As an important point of reference, the projected 2023 LCOE for black coal is $110/MWh.

Chart A1: VRE penetration and real Australian consumer electricity prices



WattClarity23 reviewed the NEM data to see if wind generation was becoming more efficient and how "… capacity factors for wind farms in the NEM have evolved over the past two decades." The major result of the review is summarised in Chart A1 based on which WattClarity concluded:

"*Although there are individual years where capacity factors have trended upwards, or even downwards, there appears to be no consistent trend that newer wind farms have been yielding a higher utilisation than those built in previous years (or even those built in previous decades). South Australia looks to be the only exception, although the underlying cause remains unclear without more comprehensive examination. It could be argued that in other regions, capacity factors for newer wind projects may even be slightly diminishing with time.*"

Further, as this organisation has argued on several occasions, on the assumption that the better VRE sites have been taken first, it is reasonable to assume that CFs for new-build VRE technologies will be lower than the CFs currently being achieved.

Appendix 4: CSIRO reduced the robustness of the treatment of Weather Droughts

Since GenCost21 Final, Weather Droughts (see Appendix 5) are accounted for by using the maximum integration costs modelled over nine weather years and states that the "… *maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation.*" (Page 57 and GenCost25 Draft page 62). Thus, the GenCost models a reliable system under the **worst** observed outcome. Currently that observation period is 2011-2019.

This short period does not meet the standards for planning infrastructure and land-use planning which look to significantly longer periods; e.g., a one in a 100-year event or a 1% chance of an event occurring in the next year.

Earlier CSIRO analysis based its estimates of the amount of Storage required to achieve a reliable system under conditions **significantly worse** than observed.

CSIRO Roadmap reported the results of a detailed analysis and modelling of the levels of battery capacity (i.e., Firming Capacity) required to be installed to ensure a reliable supply as the VRE Share in the system increases. In particular, the CSIRO Roadmap derived estimates of the Firming Capacity required to support VRE through Weather Droughts to ensure that modelled systems were "… *robust under highly unlikely weather conditions.*" (Page 116). A major conclusion of the Roadmap was: "*The modelled system is able to reliably match supply and demand for a period of poor weather conditions (i.e. low wind and sun) significantly worse than the worse period observed between 2003 and 2011.*" (Page 44). The "significantly worse" conditions were derived by repeating the "worst" week observed in the observation period and repeating it for three continuous weeks. (Page 116).

This standard was applied in GenCost18 Final and GenCost20 Final where VRE technologies were supported by 2 – 6 hours of Storage based on the CSIRO Roadmap. The result was that the cost of Firmed VRE was in the range of black coal and gas in FY30. The CSIRO made no comment in GenCost 18 and GenCost 2019-20 regarding the lowest cost, new build generation technologies.

In GenCost21 Final, CSIRO replaced the VRE plus Storage methodology with the STABLE model to estimate the optimised investment profile and operation to achieve reliability and security because the earlier approach was temporary and too conservative.

In changing the modelling methodology, CSIRO also lowered the level of weather risk from "significantly worse" to "worst" observed.

The less conservative results were that Firmed VRE technologies were now significantly less costly than gas or coal with the CSIRO making the following statement: "*When added to variable renewable generation costs and compared to other technology options, these new estimates indicate that wind and solar PV remain the lowest cost new-build technology up to a 60% VRE share.*" (Page ix).

1: GenCost18 Final referred to a "*simulated weather year included a three week "renewable drought" which was sampled from historical data.*" (Page 26). This is presumably the artificially constructed drought developed in the CSIRO Roadmap. While GenCost20 Final made no reference to weather, is used the same Storage assumptions to Firm VRE technologies.

Weather Droughts

The major determinant of the generation from wind and Solar PV technologies are wind speeds and irradiance levels (**VRE Resources**) in each time period. A major issue is that the NEM regions are regularly subject to extensive periods when VRE Resources are low (**Weather Droughts**).

In several communications regarding various GenCost reports, this organisation has drawn attention to this issue, especially in regard to the lack of account taken of Weather Droughts in setting the amount of Firming capacity required to ensure a reliable system.

The EPIA Paper stated:

"*The analysis of AEMO data reported by the Independent Engineers and Scientists in their "Response to Draft AEMO Integrated System Plan, 10 February 2022" shows multiple events of wind CFs below 10%, lasting at least 18 hours. In other periods, CFs dropped to virtually zero for days …"*) (Page 20).

ARDL23 noted that the CSIRO Response stated: "*Given Australia's large size, weather events are mostly non-synchronous across the length of the NEM.*" (Page 14). ARDL23 further noted that this "*… statement contradicts the results of other studies (e.g., GenInsights21, Deep Dive 27 – Exploring Wind Diver*sity"). (Page 25).

While the CSIRO has yet to provide any evidence to support the statement in the CSIRO Response, further studies continue to demonstrate the adverse impact on wind CFs.

A recent study by the Australian Energy Council (AEC24) entitled "Dunkelflaute writ large - May 2024" states:

"*Over the eight days from 20-27 May 2024 the capacity factor for the NEM VRE averaged 14 per cent. This is well below the 2023/24 annual capacity factor implicit in the Australian Energy Market Operator's Integrated System Plan (ISP) of 25 per cent*".

Table A1 sets out the average wind capacity factors for the regions of the NEM and the NEM for 20 – 27 May 2024.

Table A1: Average wind capacity factors eight days 20 – 27 May 2024

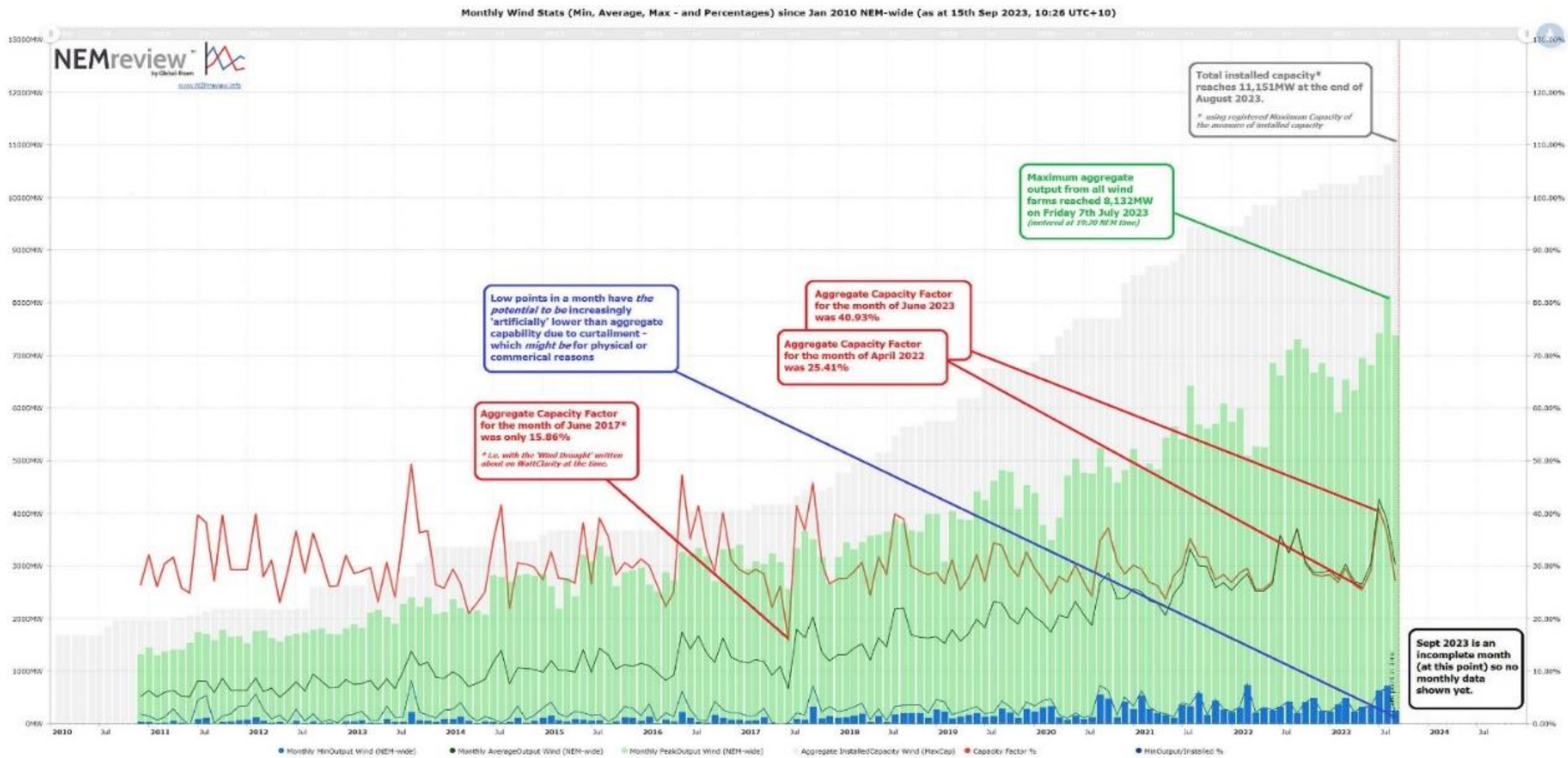
NSW	QLD	SA	TAS	VIC	NEM	NEM EX QLD
7.9%	34.4%	10.9%	20.9%	8.0%	11.6%	9.4%

The major message from these results is that the system cannot rely on Storages to refill and so must carry significantly more than sufficient dispatachable capacity to ensure a reliable system under these conditions.

They also highlight the danger of using maximum historical CFs in LCOE calculations.

Finally, Chart A2, published in NEMreview by Global Roam demonstrates that the minimum monthly aggregate wind CF in the NEM was effectively zero over several months in the last decade.

Chart A2: NEM monthly wind generation – January 2010 to September 2023



Appendix 6: FE estimate of pre-FY30 transmission project costs

Table A2 sets out the estimated cost of the pre-FY30 transmission projects reproduced from Table 6: Transmission projects – summary data (pages 36 – 40).

Table A2: Average wind capacity factors eight days 20 – 27 May 2024

Project	Full-Service Date	Latest Capital Cost $million	Range	Lowest $million	Highest $million
Project EnergyConnect	Dec-27	2,715		2,715	2,715
Waratah Super Battery	2025	1,019		1,019	1,019
Central-West Orana REZ	Aug-28	5,450		5,450	5,450
CopperString 2032	Jun-29	6,000		6,000	6,000
HumeLink	Dec-26	4,920		4,920	4,920
Hunter-Central Coast REZ Network Infrastructure	Dec-27	453	+/-50%	227	680
Sydney Ring South	Sep-28	1,550	+/-30%	1,085	2,170
Sydney Ring North (Hunter Transmission Project)	Dec-28	1,099	+/-50%	550	1,649
Gladstone Grid Reinforcement	Mar-29	1,492	+/-50%	746	2,238
Mid North SA REZ Expansion	Jul-29	416		416	416
Waddamana to Palmerston transfer capability upgrade	Jul-29	113		113	113
Victoria-New South Interconnector West (VNI West)	Dec-29	3,946	+/-30%	2,762	5,130
Darling Downs REZ Expansion	2027/28	28	+/-50%	14	42
Far North Queensland REZ	2024	40		40	40
Total		**29,241**		**26,056**	**32,581**

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