Paul Graham,
CSIRO
34 Village Street
Docklands VIC 3008

Dear Mr Graham

The Clean Energy Council (CEC) welcomes the opportunity to provide feedback on CSIRO and AEMO's GenCost 2019-20 preliminary results.

The CEC is the peak body for the clean energy industry in Australia. We represent and work with hundreds of leading businesses operating in solar, wind, hydro, bioenergy, marine and geothermal energy, energy storage and energy efficiency along with more than 6,500 solar installers. We are committed to accelerating the transformation of Australia's energy system to one that is smarter and cleaner.

Following input from a small number of our wind, solar and energy storage members, the CEC suggests the following improvements to the model's inputs and assumptions in GenCost 2019-2020 report,

- Levelised Cost of Electricity (LCOE) of wind should be reduced to $45/MWh as we expect the cost of wind energy to drop another 36% by 2030, and 48% by 2050, to around USD$30/MWh.
- Capital cost prices for wind technology should range between low-level of $1,700/kW and high-level of $1,800/kW.
- Economic life of wind should be increased to 25-30 years, while construction time of a wind farm modified to one and half to two years.
- A discount of 25% given to the balance of plant (BOP) to consider economies of scale in building a large scale versus rooftop PV plant is too high.
- Battery storage costs are overestimated and needs to be revised.
- Pumped hydro costs are underestimated and needs to be revised.

We would be very happy to discuss these issues in further details. We look forward to contributing further to this review.

Kind regards,

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Our suggestions on generation cost model inputs and assumptions on wind, solar and energy storage

<u>Wind and solar technology</u>

One wind farm developer has reviewed the CSIRO report and completed the data from Appendix Table B.5 to their current project and development assumptions books. Their suggestions are as below,

Data point	Table B.5 Data	Unit	Suggestion
Economic life	20 year	Years	25-30 years to reflect current business cases
Construction time	1 year	Years	1.5-2.0 years. 1 year is too short based on the average size of projects in Australia (>50MW)
O&M fixed	21.9	$/kW (AUD)	Appropriate
O&M variable	2.7	$/MWh (AUD)	Appropriate
Capital (Low)	1700	$/kW (AUD)	$1700 - $1800 See below
Capital (High)	1800	$/kW (AUD)	$1700 - $1800 See below

Reference points for capital expenditure (CAPEX) costs: our wind farm developer has taken the announced value and size of their committed project as well as the current assumption book figures for the most advanced development wind project.

Another original equipment manufacture of wind and solar suggests the following improvements to Section 4 on Levelised Cost of Electricity (LCOE).

Reviewing the data presented in the following graphs, it estimates the LCOE based on below data, Figures 4-1, 4,2, 4-3 and 4-4:

Year	Wind	Solar
2020	$52 - $70	$35 - $55
2030	$50 - $60	$30 - $45
2040	$45 - $55	$20 - $30
2050	$45 - $55	$20 - $25

The same original equipment manufacturer of wind and solar has graphed Power Purchase Agreement (PPA) results for wind projects that have been published, results from the ACT tender rounds (shown in blue in figure 1) and estimated level and the Snowy Hydro and another site in Australia, which is shown at $45 level (shown in orange in figure 1). They recommend the minimum level already achieved in 2020, should be reduced to $45, as wind is already below the $52 indicated by the report. This is 10 years earlier than previously nominated in the report, therefore subsequent years for 2030, 2040 and 2050 would also see reductions based on the learning rate[1].

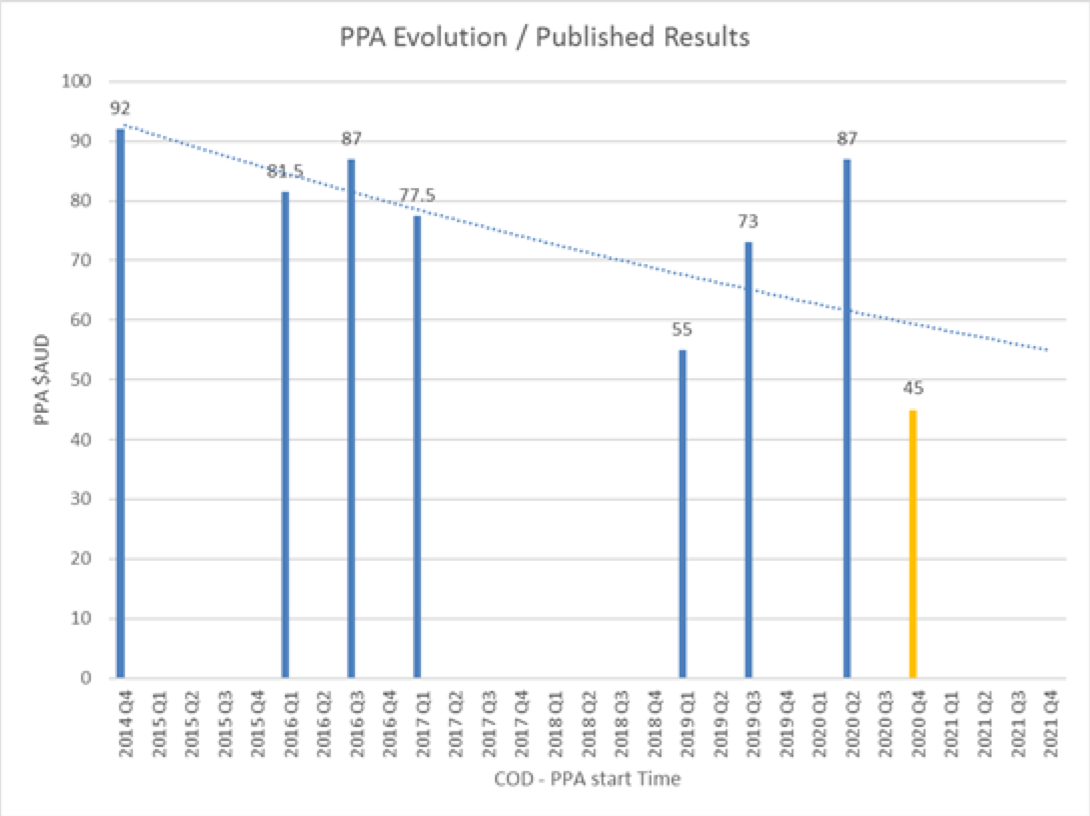

Figure 1: The Power Purchase Agreement (PPA) published results from the ACT tender rounds and estimated levels for Snowy Hydro and another site in Australia[2].

Wind turbine costs are down 40% since 2010 while machine efficiency is up, and the use of sensors and smart data helps optimise operational efficiency and reduce costs. New turbine models are also entering the market, opening access to sites that developers considered uneconomic not long ago. This original equipment manufacturer of wind and solar expect the cost of wind energy to drop another 36% by 2030, and 48% by 2050, to around USD$30/MWh."

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[1] This outlook is supported by Bloomberg, Source - https://about.bnef.com/new-energy-outlook/
"Wind energy is getting cheaper too – and fast
[2] Commercial-in-confidence market data from original equipment manufacture of wind and solar (CEC member).

Section: A.1.3 Technologies and learning rates. Learning rates for future calculation of LCOE of GenCost 2019-20 report on page 27,

Technology	Component	LR 1 (%)	LR 2 (%)	References
Photovoltaics	G	20 then 35	10	(Fraunhofer ISE, 2015; Hayward & Graham, 2013; Wilson, 2012)
	L	-	17.5	As above
Onshore wind	G	-	4.3	(Hayward & Graham, 2013)
	L	-	11.3	As above
Offshore wind	G	-	3	(Samadi, 2018) (van der Zwaan, Rivera-Tinoco, Lensink, & van den Oosterkamp, 2012) (Voormolen, Junginger, Sark, & M,

On page 28 of GenCost report states that, “However, a discount of 25% is given to the balance of plant (BOP) to take into account economies of scale in building a large scale versus rooftop PV plant.”- the learning rate proposed at 25% appear excessive, which would have significant impact on 2030 and beyond LCOE for large scale solar. This is also in light that there is a significant amount of manual labour being required for the installation of the panels and tracking systems. Our member with some experience in solar believes that these prices underestimate grid connected large scale solar LCOE.

Reviewing Table B.5 Data Assumptions for LCOE of GenCost 2019-2020 on page 39

	Constant						Low assumption					High assumption				
	Economic life	Construction time	Efficiency	O&M fixed	O&M variable	CO_2 storage	Capital	Fuel	Capacity factor	Emission factor	Carbon price	Capital	Fuel	Capacity factor	Emission factor	Carbon price
	Years	Years		$/kW	$/MWh	$/MWh	$/kW	$/GJ		$ktCO_2e/PJ$	$\$/tCO_2e$	$/kW	$/GJ		$ktCO_2e/PJ$	$\$/tCO_2e$
Wind	20	1.0	100%	21.9	2.7	0.0	1897	0.0	44%	0.0	16.9	1895	0.0	35%	0.0	28.7
Large scale solar PV	30	0.4	100%	17.0	0.0	0.0	740	0.0	32%	0.0	27.5	810	0.0	19%	0.0	50.1

The same member mentioned that the standard design life for wind farms in Australia is 25-30 years, rather than 20 years. As wind turbine generator (WTG) machines increase in MW rating from 4MW to 5 MW we are seeing reduction on the $/kW in the order of ~10%.

Original equipment manufacturer of wind and solar would also like to add a general comment regarding time of day generation for wind and solar. Time of day of generation analysis for wind and solar is increasingly important for the grid and for investors. But it is also critical for the estimation of the cost of firming. A good wind farm will need a lot less storage to go “firm” than any solar farm. And a fixed-panel solar farm will need a lot more than a single-axis tilt system. This does not appear to be reflected in the analysis but should be.

Solar PV technology

Two solar PV manufactures agree with the quoted trends and costs for large-scale solar PV. The capital cost estimates provided for large-scale solar PV in the previous year and for 2019-20 align well with their own experience and expectations.

In relation to Figure 3-10 on page 15, there’s a noticeable ‘gap’ between the cost projection under the Diverse Technology scenario compared to other scenarios. We assume that this is due to additional costs associated with building in areas with limited access as per the definition on page 7. We would question the results if the cost difference was instead due to slower growth in installed capacity under the Diverse Technology Scenario. Even if Australia’s install rate was to slow, we expect the cost of solar PV to follow international trends.

More generally, these solar PV manufacturers experience has shown that capital costs of large-scale solar PV are gradually falling and in turn, contract costs (full Engineer Procure and Construct) are also decreasing. They are however experiencing greater difficulty in reaching consensus on shared risk for project completion and commissioning with EPCs. This is arising from increased concerns over commissioning delays and inverter performance issues. They anticipate commissioning risk to continue to influence EPC/ developer risk appetite and expect this to influence contract prices and project outcomes for financial close and completion at least in the immediate and near future. This touches on the growing investor uncertainty stemming from a lack of energy policy and growing concerns over grid integration challenges. These are the challenges our members expect will influence overall project costs and contract costs moving forward.

Battery storage technology

One utility scale manufacture provided the following suggestions to battery storage costs and assumptions,

- **Updating input costs for storage** – to reflect the latest pricing. AEMO/CSIRO's 2020 capital cost forecasts are still too high for batteries. We are already observing AEMO/CSIRO's forecast 2030 battery storage prices for projects occurring today. AEMO/CSIRO appear to be relying on inputs that place battery storage at the upper bound of pricing intel. Fixed operating cost assumptions for battery storage are also higher than observed market values.
- **Incorporating market-reflective value potential** – AEMO/CSIRO's modelling must consider the additional capabilities and flexibilities beyond energy generation provided by both stand-alone battery storage as well as hybrid battery assets when paired with renewables. This will more accurately reflect the role and value of battery storage and better map to actual and expected market behaviour relative to other generation plant, without simply relying on oversimplified capital cost comparisons based on energy related costs ($/kW or $/kWh) - which should be used with caution for informing investment decisions/ credible system modelling.

They support the approach to revise the CSIRO/GHD GenCost 2018 figures and to iterate new entrant cost curve assumptions to reflect latest available market data. As with any consultative process, and particularly for technologies seeing rapid innovation in manufacturing, design and deployment, these cost models must be compared against the latest pricing being seen for real-world projects being constructed around the world.

As a high-level comparison, the same utility scale manufacturer has compiled some figures to benchmark against CSIRO's cost forecasts – highlighting that CSIRO's current battery storage pricing assumptions do not reflect what we are observing in the market:

- 2hr BESS pricing is already <$1,000/kW (compared to CSIRO assumptions >$1,400/kW)
- 4hr BESS pricing is already <$1,500/kW (compared to CSIRO assumptions >$2,000/kW)

Our utility scale manufacturer points to Aurora Energy Research and BNEF analysis that provide examples of more accurate capital inputs. Prices are $AUD and reflect fully installed systems, inclusive of balance of plant and other EPC and network connection costs. It is also worth noting that these figures reflect real-world projects that have achieved financial close and have already or will be deployed before the end of 2020.

The forward outlook on price declines appears to be based on a reasonably linear curve, with over 60% capital cost reductions out to 2040. Forecasting technology costs is a complex task and typically overestimates costs compared to what plays out in reality – with significant step change costs occurring unpredictably and often resulting in a more exponential cost reduction. At a minimum CSIRO/AEMO should update the starting figures for pricing, with additional cost reduction outlooks factored into the different scenarios. It is also unclear why the fast, high-DER and step change scenarios have higher battery storage cost assumptions than the central and slow change scenarios when it would be more likely to have higher levels of deployment driving additional cost reductions in battery storage projects being integrated into the NEM.

Given the results of the draft 2020 ISP shows a significant lack of utility scale battery storage capacity being developed (across all scenarios and states) - inconsistent with observed market outcomes, our utility scale storage member strongly recommends CSIRO/AEMO re-open its inputs for sensitivity testing with updated capital cost (and technical parameter) inputs – as battery storage assets have already demonstrated their competitiveness (in real-world deployment scenarios) against other generation assets currently being substituted in AEMO's ISP modelling, most notably pumped hydro storage and peaking gas generation. Alternatively, CSIRO/AEMO could present storage requirements based on duration characteristics rather than technology types to ensure technology neutrality – letting the market decide based on real-world value potential. Failing to recognise the role of grid-scale batteries could undermine credibility of the broader ISP and severely damage the business case for battery storage in the NEM. This may influence government and developers in selecting particular technologies due to the perception they are lowest cost.

They note AEMO/ CSIRO has assumed fixed OPEX of $8.13/kW/year for existing grid-scale battery storage projects. This value is also higher than actual values observed in the market – where OPEX over the entire lifetime of a project typically equates to 4-5% of the total upfront CAPEX value, so more in line with $3 to $5/kW/year for 2019-20 projects.

Pumped Hydro Technology

The same utility scale manufacture gave the following suggestions for pumped hydro costs and assumptions. AEMO's pumped hydro energy storage (PHES) has a range of $/kW capital cost assumptions across 6, 12, 24, 48 hours (although CSIRO only incorporates 6 hours storage into their modelling). However, it appears these assumptions do not factor in the additional premium of deploying pumped hydro in reality – e.g. elevation and reservoir locational restrictions, water utilisation and availability/drought risks, additional complexities in environmental and water planning approvals, deployment restrictions - all leading to additional development risks and process costs. It is also not clear whether the additional transmission costs are factored into new build PHES – a much greater factor than with grid-scale battery projects (the connection costs assumptions for PHES appear to have a $0/kW value in the updated workbook). As a reference point, AEMO's ISP assumptions cite $1,550/kW (6 hour) to $3,426/kW (48 hour), compared to a study conducted by PNM[3] which notes direct costs ranging from $2,100/kW to $4,225/kW, before incorporating additional deployment costs to reflect configuration, environmental/regulatory constraints, topography, geology, sizing, transmission upgrades etc. which can add an additional 15 to 30 percent of indirect costs, giving a range closer to $2,700 to $5,500/kW. In contrast, pumped-hydro assumptions do not reflect the practical challenges of deployment or operational availability and need to incorporate related risk-premiums.

[3] PNM Energy Storage technology assessment report: https://www.pnm.com/documents/396023/1506047/11-06-17+PNM+Energy+Storage+Report+-+Draft+-+RevC.pdf/04ca7143-1dbe-79e1-8549-294be656f4ca