GenCost preliminary results webinar: questions and answers

This document is a summary of the answers given during the GenCost preliminary results webinar held 1:30pm on 31 January 2020. In a small number of cases, we provide additional detail or answers to questions that were not able to be addressed in the time constraints of the webinar. Spelling and grammar have not been checked for the questions to preserve their original state as provided by webinar participants.

Note on submissions and the planned use of GenCost 2019-20 data in AEMO processes

This is a brief note to clarify the submission process and how the data will be used once submissions have been received and incorporated. The GenCost 2019-20 report has been included in a range of documents that have been made available for public submissions in AEMOs 2020 Integrated System Planning (ISP) process. Whilst submissions are being taken for the draft projections during the 2020 process, data from GenCost 2019-20 will not be applied by AEMO until the next ISP process. However, it will begin to be used in other AEMO planning and forecasting exercises in 2020 (e.g. ESOO 2020) and future ISP rounds and is available to be used immediately by other stakeholders for their own purposes. Submissions on the draft GenCost 2019-20 report are due February 7th to forecasting.planning@aemo.com.au.

Questions and answers

Q: Will slides be provided after the meeting?

A: Yes

Q: What DC/AC ratio did you assume for the solar PV costs? (presume single-axis tracking)

A: These assumptions were determined by Aurecon. See page 21 of Aurecon 2019 Cost and Technical Parameters Review Draft Report which assumes 120MW DC and 100MW AC for a single axis tracking unit.

Q: Did you look at solar thermal at all?

A: Solar thermal is included in the report but was not covered in the webinar due to time constraints. Generally speaking, solar thermal capital costs are a little higher than in the 2018 projections in the near term because we no longer expect a local project to proceed (previously planned for South Australia). The lack of a domestic project means that local installation costs remain higher for longer but we still benefit from cost reduction due to international project deployment.

Q: Why was battery storage limited to 2 hours rather than supply both 2 and 4 hour storage options

A: Aurecon provides current battery storage costs and performance characteristics for 1, 2, 4 and 8 hour battery storage projects while the GenCost projections are for 2 hour projects only. This is because the projection model is limited in the number of technologies it can include by the computational constraints of a multi-region global model. However, we provide a break-down of battery and balance of plant components so that the 2 hour cost projection can be used to create a 4 hour cost projection (the battery pack component is fairly modular).

Q: Did you look at PHES > 6hrs?

A: As above, we cannot include more storage size variations in our projection model but alternative PHES storage size costs are dealt with in this report: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf

Also note that, because PHES is a mature technology we do not project a significant change in costs and therefore any current PHES costs estimates of whatever size are a fairly good indicator of future costs. We include a 5% learning rate on the tunnelling component of capital costs as this is the least mature component.

Q: Peak demand period is 4 hours we need 4 hour batteries

A: See two previous answers

Q: what are your wind capacity factor assumptions

A: Provided below.

REGION	ONSHORE WIND CAPACITY FACTOR (%)		OFFSHORE WIND CAPACITY FACTOR (%)	
	2019	**2050**	**2019**	**2050**
Africa	35.3	38.4	39.6	43.3
Australia	41.3	44.4	49.8	54.2
China	25.3	28.4	45.6	49.3
Eastern Europe	28.3	31.4	49.8	54.2
Western Europe	28.3	31.4	49.8	54.2
Former Soviet Union	33.3	36.4	49.8	54.2
India	24.3	27.4	39.6	43.3
Japan	35.3	38.4	45.6	49.3
Latin America	41.3	44.4	45.6	49.3
Middle East	29.3	32.4	34.6	38.3
North America	34.3	37.4	44.6	48.3
Other OECD Asia Pacific (NZ and S Korea)	35.3	38.4	39.6	43.3
Rest of Asia	31.3	34.4	34.6	38.3

The capacity factors increase linearly between 2019 and 2050.

Q: Can you talk about the FOM and other costs for the techs? (which must have been included in the LCOE calcs)

A: Detailed FOM and other costs are available in Aurecon 2019 Cost and Technical Parameters Review Draft Report. Also, see Appendix table B.5 on page 39 of the GenCost 2019-20 draft report.

Q: note wind appears to be getting more expensive on a nominal basis

A: Noted. We only work in real dollars terms for all projections.

Q: How are changes in capacity factor modelled - e.g. if wind or solar improve?

A: As shown in the table above: linear improvement over time.

Q: For PHES, did you look at different types of PHES construction? It varies a lot based on construction type.

A: No. We are unable to include all of the relevant technology variants for PHES or any other technology category due to the computational limits of a multi-region global model. However, the Entura report includes several different projects which may provide some guide to the amount of costs variation these variants might deliver.

https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf

Q: We saw a significant increase in the Capital cost for OCGT because of lower plant size, Can we include the larger plant sizes as well?

A: We only intend to include plant sizes that are relevant. However, we would advise going back to the GenCost 2018 or GHD report upon which it was based to get a feeling for costs at larger plant sizes. These older reports remain relevant because these are mature technologies and so you would not expect significant costs changes from year to year. For all mature technologies and technology components we include a constant annual cost reduction of -0.01%.

Q: Did you consider modelling LCOS rather than LCOE? which is arguably a more likely indicator of value in the longer term.

A: LCOS is becoming more widely used and we did conduct a review of alternatives to LCOE in 2018 (see this link: https://publications.csiro.au/rpr/download?pid=csiro:EP187001&dsid=DS3). We consider this as a future option.

Q: What are PHES costs based on? Does it take into account the latest publicly available data in regards to announced project costs estimates?

A: PHES is based on the work by Entura (see previous answers). Given PHES is a mature technology we would not expect its costs to change significantly from year to year. We do include a 5% learning rate on the tunnelling proportion of costs, as this is the least-mature component. However the Entura publication gives a good sense of variation from project to project where site costs do come into play and can vary significantly.

Q: With regards to OCGT's you indicate that the increase in costs is based on a change in sleection of GT's to smaller capacity GT's. Why didnt you include costs for both small capacity aero-derivatives and larger capacity frame-type GT's seperately

A: As discussed in other answers, due to computational limits we are not able to include both variants in our multi-region global model. See page 30 of the Aurecon 2019 Cost and Technical Parameters Review Draft Report for why the aero-derivative was chosen.

Q: What about PHES cost at various scaels? For firming an individual plant it may be different than a larger plant

A: We wouldn't expect significant changes in the costs trajectory between various scales. Please see the Entura report link in other answers to access information about costs of different projects.

Q: For batteries, we understand that the capital cost assumptions are conservative, Can we again understand the reasoning for having a high Capital Cost?

A: CSIRO relies on the input of expert consultants on all current capital cost assumptions. The Aurecon report from which current capital costs estimates are sourced is available on the AEMO website. If you have concerns about any of Aurecon's data or assumptions please make a submission to forecasting.planning@aemo.com.au.

Q: With PHES, could costs be shown for PHES based on using existing storage and PHES that requires development of storage dams as well

A: The Entura report may be able to provide an indication of storage dam costs separate from other PHES component costs.

Q: Could you please give some idea of how the battery costs might scale with storage duration?

A: If the project is only increasing the storage duration and not the power rating then the $/kWh costs for the battery pack are scalable (i.e. can be multiplied by the hours duration)

Q: Can you please put some light on the possible reason behind the large gap between actual project cost and forecasted cost in this report?

A: There are two main reasons for why we see large shifts in actual and forecasts over time. The first is that for projects that would be first of a kind in Australia the project costs are very uncertain and each consulting firm who is tasked with updating current costs for those projects often has a different view from predecessors. This applies to projects such as solar thermal, carbon capture and storage and small modular nuclear reactors. These estimates will continue to move around until we see a first of a kind plant that will establish a hard data point for Australian development costs. The second reason for large changes is that some technologies have experienced rapid improvements in costs such that, even if data is sourced from the same engineering consulting firm, they will provide a different estimate depending on the time of year. That is, costs are changing significantly within a year so that two a range rather than a single point is valid. This has applied in the past to solar and batteries which have experienced rapid decreases in within-year costs.

Q: Could still have a 2019-20 4-hr battery cost and then use the same trajectory as created by GALLM for 2-hr batteries?

A: Yes, the 2 hour battery cost trajectory information could be used to apply to 4 hour batteries. Cost trajectory data is provided for battery and balance of plant components and so these trajectories should be applied to the same components of a 4 hour battery project.

Q: Curious as to why the range for the solar voltaic + storage LCoE estimate is so much wider than wind+storage's estimate?

A: In any LCOE calculation all of the costs (power plant plus storage infrastructure plus running costs) are recovered through energy produced. In mathematical terms, all the annualised costs are divided by the annual energy. Any wind project will have a larger volume of energy produced per kW capacity than solar because of its higher capacity factor. As such, adding additional storage capital to the project costs has a greater impact on the LCOE of solar projects than on wind projects.

Q: Has any work been done to determine the optimum battery size for the NEM taking into account the VRE output profile and consumer demand profiles. 2 or 4 is based on best guestimate

A: This question is currently out of scope for the GenCost project which is only designed to provide the underlying cost data from which further analysis can be conducted to answer questions such as this. If it should become established that higher duration battery projects are more likely we could change our current focus on 2 hour duration projects. To date, existing battery projects deployed in Australia have been in the 1 to 2 hour duration range. It is possible that our work to establish the balancing costs associated with renewables will provide some insights on this question but we do not have any results to report from that work at this stage.

Q: what is the rational for keeping 4degrees as the central scenario? given recent impacts others scenarios seem to be getting more likely

C: I agree - perhaps it could be better named as "status quo"

A: We decided that the Central scenario should only include current and reasonably anticipated global climate and energy policies. As it stands, the Paris climate nationally determined commitments are collectively consistent with a 4 degrees outcome. It is possible governments will ramp up commitments, but we cannot be sure of that outcome as yet. The majority of scenarios included do assume 2 degrees. Also, as discussed during the webinar we found in previous projections that the choice of 2 or 4 degrees climate policy (and associated carbon price) has limited impact on projected costs. The carbon prices consistent with either a 2 or 4 degrees global climate policy are enough to activate the deployment of the key low emissions generation technologies. Submissions can be made on this topic to assist us in reflecting the broad views of stakeholders.

Q: just noting that "dispatchable" generation needs back up to it may be misleading to suggest only renewables need backup

A: Agreed

Q: Virtual Power Plants will depend on household rooftop solar which is highly dependent on the quality of the solar systems installed and their maintenance. Utility scale renewables are well maintained how do you account for poor quality solar that will increasingly be attractive to household budgets under stress and especially when STCs will expire ie what is the cost of power from a VPP

A: When we update current costs for rooftop solar we look at what is currently being sold. If costs fall (through selection of lower quality products) this will be reflected in the costs. AEMO also includes rooftop solar degradation in its ESOO processes. Quality changes might be reflected through changes in warranty conditions, observable output or increased degradation or failure rates. These might take some time before it is observed and factored in. The costs of VPP as a specific application or service provided by rooftop solar (perhaps with batteries) is not separately included in GenCost 2019-20. Existing work by AEMO and others may be able to answer this question. The GenCost project is planning to take a deeper look at demand management costs more broadly and may have more to say on this topic in the future.

Q: For batteries, since there is a variation between technical life and economic life, the existing methodology does not reflect the ongoing option value, How do we plan to capture it ?

A: The difference between technical life and economic life can be captured by using system models. The LCOE calculation uses economic life only because the calculation is concerned with making sure that the capital cost is paid back according to the finance terms. However, system models are more concerned with establishing how long capacity will be available once installed and so often use technical life. They may also use economic life to calculate bidding behaviour consistent with long run marginal costs. Given system models are able to capture technical life we do not intend to build it into the LCOE calculations in GenCost.

Q: You mentioned no timeline in place for DM/DR cost development. Considering the impact from a likely DRM, can you elaborate further on your plans for how this solution will be integrated into the model.

A: CSIRO's role is to provide electricity generation and storage costs for modellers and we've been requested to provide more cost data on demand management in the future. However, that does not preclude other organisations from including their own demand management costs assumptions in their modelling frameworks before we are able to deliver that data. For example, AEMO already routinely includes VPP and industrial demand management in its modelling.

Q: In the tables, the battery cost and BoP costs are both given per kWh; is this correct, or should BoP be per kW?

A: The data is correct since most storage costs are expressed in $/kWh. However if you know the power to energy ratio you can always convert to $/kW. In our case the power to energy ratio is 1:2. Therefore to convert to $/kW multiply by 2.

Q: Given the comparably lower starting point for wind - is the low learning rate still considered valid? The difference from 2018 to 2019/20 is almost as large as the entire learning.

A: The learning rate (percentage cost reduction for each doubling of cumulative capacity) for wind has been established for many years and so it is unlikely this has changed significantly. We would need more than one year's data to reconsider the learning rate assumption. It is also possible that there has been a change in how the engineering consultant responsible for updating the current costs has selected the representative project or that the types of projects constructed in 2019 differed from those in 2018 (e.g. location, size).

Q: The incredibly fast learning for SMR in diverse tech seems to challenge scarcity issues - surely there would be scarcity pricing due to excess demand. Is this still in the model - any technology which is mutliplying rapidly is at risk of supply chain constraints.

A: The model still includes penalty constraints around how much technology can be built as a fraction of the total build for a year. However it is likely those constraints are not activated in this case because the capacity of SMR being built still remains low. SMR can reduce costs without a very large increase in capacity because it is coming from a low base where learning potential is high because from a mathematical point of view it is easier to double low levels of capacity. Costs for all non-mature technologies decrease according to the number of capacity doublings. This outcome is part of the SMR manufacturer’s strategy. They are seeking to produce a lower cost nuclear plant (despite normal economies of scale) by making a more modular plant with common components and manufacturing them in series. However, although the model appears to be functioning normally we’ll take another look at this issue.

Q: Is AEMO going to consider a diverse tech scenario in the future? it is certainly an interesting scenario...

A: AEMO’s current scenarios are as stated in the ISP documents.

Q: Draft report doesn't appear to cover the uncertainties attached to these cost estimates and the variations in these uncertainties for different technologies and time frames (beyond the use of scenarios). Given the growing use of probablistic cost functions in capacity expansion modelling, is this something that CSIRO is planning to address?

A: We are not currently planning to introduce stochastic variables or Monte Carlo style exploration of uncertainty but appreciate the interest. If there is sufficient broader interest this is something we could consider for future development.

Contact us

1300 363 400
+61 3 9545 2176
csiroenquiries@csiro.au
csiro.au

For further information

Energy
Paul Graham
+61 2 4960 6061
paul.graham@csiro.au
csiro.au/energy