Modelling the Value of CER to Energy Consumers

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DOCUMENT INFORMATION

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Prepared by	Lance Hoch (lhoch@oakleygreenwood.com.au) Rohan Harris (rharris@oakleygreenwood.com.au)
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1. Conceptual basis of the modelling

The Australian Energy Market Operator's (AEMO) Draft 2024 Integrated System Plan (ISP) is heavily influenced by its forecasted uptake of Consumer Energy Resources (CER).

The forecast used in the AEMO 2024 ISP Step Change scenario is actually the average of two forecasts that were commissioned by AEMO and developed independently by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Green Energy Markets (GEM).[1]

These two forecasts are very different from one another, reflecting the highly uncertain nature of forecasting CER (particularly over a 25- to 30-year horizon). The CSIRO forecast of CER (PV and behind-the-meter battery) and its orchestration is significantly lower than the GEM forecast and materially different to the averaged forecast used by AEMO in the 2024 ISP Step Change scenario.

The level of central generation system built in the ISP modelling depends heavily on the amount and timing of energy required by consumers. CER reduces the amount of energy consumers need in total and also changes the time at which that energy is needed. As a result, the CER forecast can have a material impact on the nature of the central generation system and the costs that consumers will pay for the energy it supplies. More specifically, if the amount of CER forecasted to appear does not materialise, the projected need for new generation and transmission infrastructure will be affected, potentially requiring more infrastructure to be built, which would change the cost of supplying electricity to consumers.[2]

The Clean Energy Council engaged Oakley Greenwood to quantify the value of CER to electricity consumers. We did this by looking at what the impact would be on the central generation and transmission system if the lower of the two independent CER forecasts commissioned by AEMO – the CSIRO forecast – eventuated instead of the forecast used by AEMO in the ISP Step Change scenario.

Essentially, the modelling seeks to answer the following question:

> *How much more central generation and transmission infrastructure would need to be built if the amount of CER and orchestration taken up turns out to be what CSIRO forecast rather than what AEMO assume in the 2024 ISP Step Change scenario – and how much more would that infrastructure cost?*

The figures on the following page show the differences between key aspects of the AEMO and CSIRO CER forecasts.

1 Both these forecasts and reports can be accessed at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

2 Similarly, if more CER materialises than was forecast, less generation and transmission infrastructure may be needed than was originally forecast.

Figure 1: PV capacity (MW) take-up in the AEMO and CSIRO forecasts

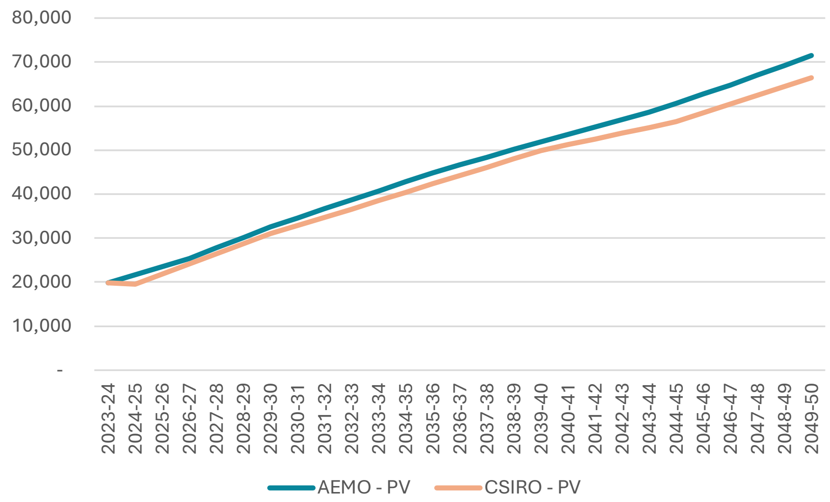


Figure 2: Un-orchestrated BTM battery capacity (MW) take-up in the AEMO and CSIRO forecasts

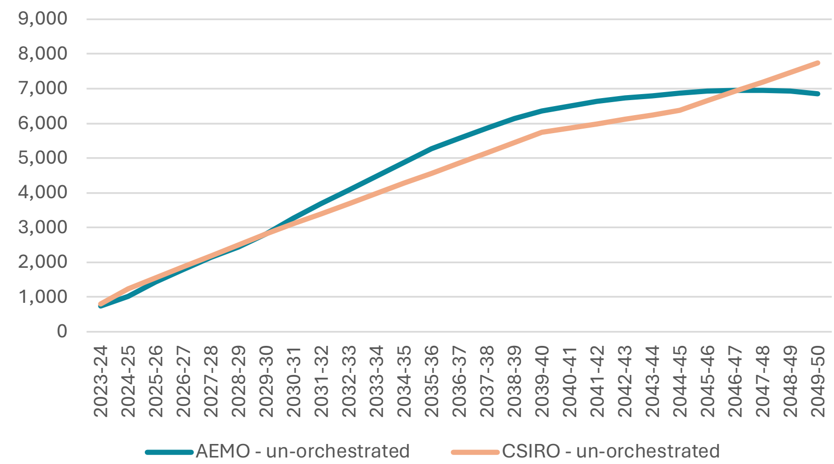
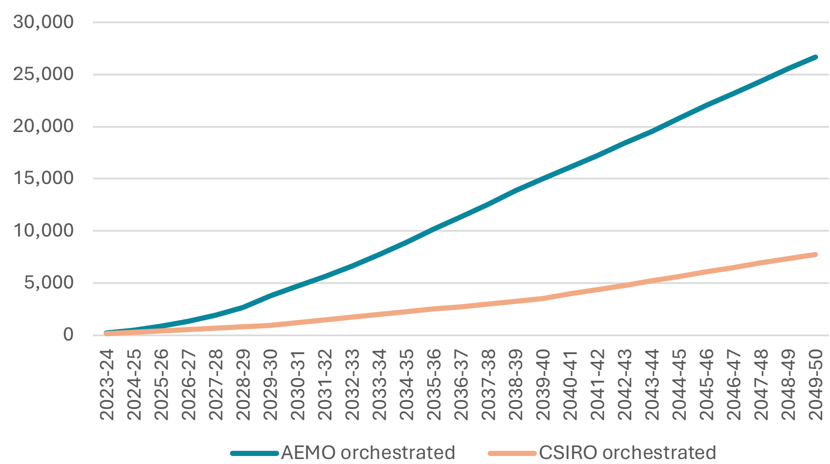


Figure 3: Orchestrated BTM battery capacity (MW) take-up in the AEMO and CSIRO forecasts



As can be seen, the biggest difference in the two forecasts is in the amount of orchestrated battery capacity. This is important because orchestrated batteries can – and AEMO's modelling assumes they will – be dispatched to balance supply and demand in the wholesale market, thereby reducing the amount of central generation and transmission infrastructure need to meet total consumer demand for electricity.[3]

[3] Orchestrated CER can also be dispatched to manage congestion and voltage levels in the distribution network. Our modelling only considered the impact of a shortfall of CER on the generation and transmission sectors. SA Power Networks undertook modelling that addressed the difference they would incur in running their network under the CSIRO forecast of CER as compared to the AEMO forecast. The results of that analysis are included in the CEC's *Powering homes, empowering people: A national consumer energy resources roadmap*.

2. Key aspects of the modelling

2.1. Overview

The modelling assumes that the shortfall in CER and orchestration resulting from the CSIRO forecast as compared to the AEMO forecast would be offset by building more centralised generation and storage (i.e., assets with very similar generation profiles to the CER assets that would be removed from the demand forecast).[4] More specifically, the modelling assumes that:

- The reduction in energy exported to the grid that results from less rooftop PV being installed (relative to AEMO's Step Change assumptions) will necessitate increasing the amount of centralised solar that is built to deliver a similar amount of energy (and production profile) to what was displaced (i.e., less rooftop PV capacity results in the need for more centralised solar capacity).

  The model calculates the amount of large-scale, central system PV needed to make up for the lower amount of PV in the CSIRO forecast, with adjustments for the difference in the capacity factors and marginal loss factors that apply to central and rooftop PV systems.

  The information used in the model for the per-MW capital and fixed operating and maintenance costs of the central PV plant are those used by AEMO in the ISP. Specifically, the model uses AEMO's costs for PV in the Central West Orana REZ.

- The reduction in the number of orchestrated batteries installed behind the meter (BTM) in customers premises will necessitate an increase in the number of grid-side batteries that need to be built, with their utilisation assumed to be broadly the same as BTM batteries that are operated by aggregators as Virtual Power Plants (VPPs), given that both are dispatchable and are operated to generate income from wholesale market price signals.

  The information used in the model regarding the capital and fixed operating costs of grid-side batteries is taken from AEMO's ISP data files. Specifically, the model uses AEMO's costs for grid-side batteries in the NSW region.

- The modestly larger number of un-orchestrated batteries installed BTM in the CSIRO forecast as compared to the ISP Step Change forecast will not affect the number of grid-side batteries needed to compensate for the shortfall in orchestrated BTM batteries between the two forecasts. This is because an un-orchestrated battery's economics (and its charge/discharge profile) is predominately driven by the retail price signals faced by end customers. These are not easily replicable for grid-side batteries.[5]

2.2. Detailed inputs and assumptions

The table on the following pages provides further information on these and other key inputs and assumption to the modelling.

4 A more formal approach – and the one AEMO uses when running different scenarios in the ISP – is to re-run its capacity expansion model. This project did not have the resources for that and has therefore adopted the approach explained here. It is worth noting that AEMO has recently announced that they plan to re-run the Step Change scenario with a lower forecast of CER take-up and orchestration.

5 The exception would be where a grid-side battery provides energy as a service to end customers, but this business model is exceedingly rare.

Table 1: Inputs and assumptions used in the modelling

Parameter	Reference for calculations	How it is calculated / used
Total deficit in rooftop PV (MW) as compared to AEMO's Step Change Case	[A]	We use the CSIRO forecast as our alternative case. The total deficit (the difference between take-up in AEMO's Step Change forecast and the CSIRO forecast) gradually increases over the forecast time horizon, such that it reaches 5.1GW by 2049/50 (see Figure 1 above).
Total difference in un-orchestrated batteries (MW) as compared to AEMO's Step Change Case	[B]	We use the CSIRO forecast of un-orchestrated battery as our alternative case. The CSIRO case results in 893 MW more un-orchestrated battery capacity being installed by the end of the analysis periods. However, in most of the years in the middle of the timeframe the CSIRO case results in much less un-orchestrated battery capacity being installed than the AEMO forecast (see Figure 2 above).
Total deficit in orchestrated batteries (MW) as compared to AEMO's Step Change Case	[C]	This is represented by the difference in BTM orchestrated battery in AEMO's Step Change case compared with the amount of orchestrated battery in the CSIRO forecast (which we have calculated). This reaches 18.9GW by 2049/50 (see Figure 3 above).
Amount of additional centralised solar that will need to be built	[D]	[A], adjusted down by 25% to reflect centralised solar's higher capacity factor (CF), offset by the higher MLFs faced by centralised solar (as compared rooftop PV).
Capital cost of the additional centralised solar that will need to be built	[E]	Unit costs are taken from AEMO's *2023 IASR Assumptions Workbook*, "New Entrant Summary" sheet [Central-West Orana REZ location information], Build Cost ($1788.35/kW) plus Connection Cost ($135/kW). This combined figure ($1,923,352/MW) is converted into an annualised figure of $170,846/MW by using the PMT formula in Excel (assuming an 8% WACC and a 30-year life). This annualised cost is multiplied by the amount of additional centralised solar required in each year [D].
Fixed O&M costs associated with the additional centralised solar that will need to be built	[F]	Unit costs are taken from AEMO's *2023 IASR Assumptions Workbook*, "New Entrant Summary" sheet [Central-West Orana REZ location information], FOM cost of $19.63/kW/annum. This FOM cost is multiplied by the amount of additional centralised solar required in each year [D]
Amount of additional centralised battery that will need to be built	[G]	[G] = [C], calculated annually. We assume that the amount of centralised battery that will need to be built in each year reflects the amount of orchestrated battery that does not occur BTM in that year (not that this does not include the amount of un-orchestrated battery that is built or not built).

Parameter	Reference for calculations	How it is calculated / used
Capital cost of the additional centralised battery that will need to be built	[H]	Unit costs are taken from AEMO's *2023 IASR Assumptions Workbook*, "New Entrant Summary" sheet ['Battery Storage (4hrs storage) – NSW Region'], Build Cost ($2,455.15/kW) plus Connection Cost ($77.52/kW). This combined figure ($2,532,679/MW) is converted into an annualised figure of $257,959/MW by using the PMT formula in Excel (assuming an 8% WACC and a 20-year life). The annualised battery cost is multiplied by the annual amount of centralised battery capacity that is assumed to be built [G].
Additional fixed O&M costs associated with the additional centralised battery that will need to be built	[I]	Unit costs are taken from AEMO's *2023 IASR Assumptions Workbook*, "New Entrant Summary" ['Battery Storage (4hrs storage)' – NSW Region], FOM cost of $18.71/kW/annum. This FOM figure is multiplied by the annual amount of centralised battery that is built in each year [G].
Additional transmission capacity that will need to be built to accommodate that new additional centralised solar	[J]	[J] = (1/2 * A) We assume the additional transmission capacity (MW) that must be built equates to ½ of the additional amount of central solar capacity (MW) that needs to be built. This reflects an assumption that some of the centralised batteries that will need to be deployed to offset the reduction in BTM orchestrated batteries will be deployed close to (if not co-located with) the new central solar generation that is assumed to be built.
Cost of additional transmission capacity	[K]	The cost of the additional transmission capacity that is assumed to be required to accommodate the centralised PV that results from the reduced amount of rooftop PV is based on the incremental cost of increasing the size of a future stage of the CW Orana REZ. The unit cost of this expansion has been taken from AEMO's *2023 IASR Assumptions Workbook*, "Build Limits" (Central-West Orana, Tranche 3). The incremental cost is $0.55m/MW. This cost gets converted to an annualised figure of $46,123/MW by using the PMT formula in Excel (assuming an 8% WACC and a 40-year life). This annualised cost is multiplied by the amount of additional transmission capacity that is required in each year [J]
Economic cost of deficit in un-orchestrated batteries as compared to AEMO's Step Change		We assume that every un-orchestrated battery installed under AEMO's Step Change scenario contributes in the order of $200/per battery (or $40/kW, based on a 5kW size). This amount reflects the following assumptions: • **Wholesale market benefits**: We have relied on the AER's CECVs, which represent the short-run marginal cost of the marginal generator in each half hour, as a proxy for the economic costs that will be imposed on the system if AEMO's Step Change forecast of BTM batteries is not achieved. In simple terms, we overlaid the profile of an un-orchestrated battery on the CECVs to determine the impact that its charge/discharge profile would have on wholesale costs at the margin. Whilst the impact varies over time, as forecast wholesale costs change with increased penetration of centralised solar and wind, for the purposes of this analysis we have simply assumed a constant economic benefit per battery.

Parameter	Reference for calculations	How it is calculated / used
		• **FCAS:** We assume that un-orchestrated batteries do not provide any FCAS benefit. • **Network support:** We assume that un-orchestrated BTM batteries provide some level of network support as a result of their underlying charge/discharge profile. The economic value we ascribed to that network support was based on the published LRMCs of the distribution businesses operating in NSW ($70/kVA/pa), as well as a small allowance for the LRMC of the state's transmission system ($10/kVA/pa). The value of the network support provided by the battery reflects the net amount of energy the battery's charge/discharge profile indicates would be discharged on average over the peak demand period (assumed to be 6pm in summer).

3. Results

3.1. Impacts on costs in the central generation and transmission system

The modelling shows that over $19bn would be required in additional central system costs if the CSIRO forecast of CER take-up and orchestration were to eventuate instead of the level forecast in the Step Change scenario. This is made up of approximately:

- $3.1bn for additional central PV generation capacity
- $16.2bn for centralised storage capacity for firming
- $0.5bn for additional transmission capacity

Our analysis assumes the above would increase by a small amount (about $80m) because for the majority of the period the AEMO forecast results in a greater number of un-orchestrated batteries, meaning that the CSIRO forecast would not include the benefit those batteries provide.

The table below provides further information on the sources of these additional costs.

Table 2: Additional central system costs due to the lower level of CER take-up and orchestration in the CSIRO forecast

NPV to 2050 (2023$m)	Area of supply chain	Type of cost
$2,836.5 $326.0	Large-scale PV generation	Capital cost Fixed operation and maintenance
$15,086.2 $1,094.1	Large-scale centralised battery storage	Capital cost Fixed operation and maintenance
$510.2	Transmission	Capital cost
$19,853.4	Subtotal	
$79.8	Large-scale PV generation, transmission and distribution	Reduced benefit due to fewer un-orchestrated BTM benefits in the CSIRO forecast
$19,933.1	Total	

This total amount (just under $20bn) represents the additional cost that would need to be spent on the additional central generation, storage and transmission infrastructure if the CSIRO forecast of CER deployment and orchestration were to eventuate as compared to the AEMO Step Change CER forecast. Put another way, it represents the maximum amount that could be spent on policies and/or programs that would ensure level of CER take-up and use assumed in the Step Change scenario is realised.

However, it is important to note that the analysis does not consider the following costs or potential impacts:

- The costs that would have been incurred by the retailer or VPP operator in incentivising the owners of BTM batteries to allow them to be orchestrated.

- The costs that would have been incurred by distribution businesses to accommodate the levels of CER forecast in the ISP (i.e., any cost required to increase hosting capacity), which might be reduced in the CSIRO case. However, SA Power Networks have modelled the difference that the two forecasts would make to the costs their network would incur going forward. Their results and an extrapolation of them to the whole of the NEM are provided in the CEC's *Powering homes, empowering people: A national consumer energy resources roadmap*.
- The impact that more grid-side batteries might have on the distribution network under the CSIRO case, noting that the impact grid-side batteries have on the distribution system peak demand will depend on the location of the grid-side batteries within the grid. For example, everything else being equal, the higher the voltage at which a grid-side battery is connected, the less ability it will have to reduce peak demand or manage voltage levels at lower voltage levels of the distribution network.
- The reduced expenditure on CER by consumers in the CSIRO forecast as compared to the Step Change forecast.

3.2. Other impacts

Other impacts identified in the modelling are shown in the table below.

Table 3: Other impacts identified in the modelling

Item	Result	Explanation and/or derivation
CER consumer investment (historical)	• PV: About $20 billion (2020 $) from 2013 to 2020 • Battery: $1.0 to $1.5 billion (2021-22 $) from 2018 to 2023	Based on CER data on the number of systems installed and CSIRO data on size and cost of systems purchased
CER consumer investment (going forward)	• PV: About $35 billion (June 2023 $) from 2025 to 2050 • Battery: About $20 billion (June 2023 $) from 2025 to 2050	Based on CSIRO annual forecasts of the number of systems installed, and the average size and cost per unit capacity of the systems
Job creation (historical)	• About 17,500 FTEs in PV • About 700 FTEs in battery storage systems • Both include manufacturing, installation & maintenance jobs	Based on AEMO employment factors (2023 IASR) and CER data on MW capacity of systems purchased
Job creation (going forward)	• About 11,000 FTEs in PV over the period from 2025 to 2050 • About 3,500 FTEs in battery storage systems over the period from 2025 to 2050 • Both include manufacturing, installation & maintenance jobs	Based on AEMO employment factors (2023 IASR) and CSIRO forecast of MW capacity of systems to be purchased
Avoided emissions and contribution to meeting renewable energy and climate targets	Essentially NIL	We have assumed that the amount of central PV and battery required to fill the gap between the Step Change and CSIRO forecasts can be built in the timeframes needed. However, if the required REZ assets cannot be delivered on time – e.g., if the needed transmission capacity cannot be built in time – fossil plants like Eraring may need to stay on-line longer, which would result in additional emissions.
Savings on bills overall	$7.50 per MWh per year	Calculated as:

Item	Result	Explanation and/or derivation
	For an average NSW customer using 5MWhpa, this would be $37.50pa or $1,012.50 in total (2023 $) between now and 2050	• $19.9 bn (which is the present value of the costs that would be incurred if central PV and battery needed to be built to make up for difference in BTM PV and orchestrated battery between the Step Change and CSIRO forecasts) • Divided by the present value of AEMO's forecast of annual consumption (operational, sent out) across the NEM
Savings to a CER customer	• PV & non-orchestrated battery: $900 to $1000 pa • PV & orchestrated battery: $1,150 to $1,500 pa, noting that the exact amount will depend on the customer's retail price and the benefit sharing or other incentive arrangement made available by the operator of the VPP	Reduced retail bill, assuming an 8kW PV system, a $0.35/kWh retail price, and a 5kW/10kWh battery.