Project Symphony

Our energy future

Work Package 2.3

DER Service Valuation Report

In partnership with:

Western Power Synergy AEMO Government of Western Australia Energy Policy WA

Document Control

Disclaimer: Project Symphony received funding from the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program. The views expressed herein are not necessarily the views of the Australian Government, and the Australian Government does not accept responsibility for any information or advice contained herein.

Neither this report, or the inputs to it, should be taken to represent the views of Synergy, AEMO, Western Power or the Government of Western Australia. The report was commissioned, and certain inputs provided on a hypothetical basis, for the purposes of Project Symphony. AEMO provided advice on the Wholesale Electricity Market and public data sets for the development of this report.

This report outlines a potential set of methods for valuing services provided by resources contributing to the Project Symphony pilot only. The Symphony partners support this report on the basis that it illustrates the potential operational value streams of the Project Symphony pilot. However, as the methods are proposed for a simulated rather than real market scenario, they will not necessarily be reflective of actual market behaviour. The methods described herein should not be considered as a basis for investment and interested parties should undertake independent modelling to inform such decisions.

Project Symphony
Our energy future

Table of Contents

1 Executive Summary

This paper is the ARENA deliverable for Project Symphony Work Package (WP) 2.3, the main purpose of which is to present a set of computational methods to value the operating cash flows across the energy system, including customer, network, retail and market, associated with the pilot's Distributed Energy Resources (DER) assets. It will also describe the techno-economic simulation tools that will be developed to determine the actual value of DER services that will be deployed or integrated through the pilot.

The architectural design of the DER services valuation approach is illustrated by Figure 1 below. At a high level, the approach transforms half-hourly market data inputs to a set of modelling outcomes, by combining observed DER load and generation control data with market simulation and customer baselining estimation techniques, and by applying a set of pre-defined formulae to evaluate and compare the cash flows associated with the pilot.

Figure 1: High-level architectural design of the DER services valuation approach

Reported outcomes will be framed as a comparison between the operating cash flows that would occur under DER orchestration and participation in markets, to those that would occur under an assumed non-orchestration base case. The core components of the framework are summarised in the following subsections.

1.1 DER asset data and customer base case

An assessment of the value of orchestrating a DER device as part of the Project Symphony virtual power plant (VPP) requires an estimation of how that device would have been operated if it were not part of the VPP. To achieve this, a standardised capability built into Enbala's Concerto aggregation platform procured by Synergy will be used to estimate customer loads and battery energy storage utilisation in the absence of a VPP orchestration 'event' (i.e., the 'non-orchestration base case') as follows:

- Controlled load assets (i.e., air conditioners, hot water systems and pool pumps) - asset baseline load values will be determined by taking the average of three days out of the five most recent 'similar days' with the highest loading conditions in the absence of a VPP orchestration event. For air conditioning loads, a further 'weather adjustment' of the baseline will be made for days with higher-than-recent-average loads.
- Controlled battery assets - the battery baseline will be based upon a calculation of what the battery would have been doing if it were in self-consumption mode, rather than being subjected to orchestration, resulting in a grid net export of zero subject to available battery capacity.

For curtailed rooftop solar assets, baseline load values will be determined by linear extrapolation between the inverter output recorded immediately prior to the start of a curtailment event period and that recorded immediately following the end of the event, unless the observed inverter output is below the constrained inverter setpoint output level, in which case the baseline will be the observed inverter output.

1.2 Market clearing and generation cost simulation

For each trading interval, the Australian Energy Market Operator (AEMO) will conduct a market clearing simulation by adjusting the market's balancing merit order and operational demand for the operation of the VPP. AEMO will also provide an essential system services (ESS) contingency raise price proxy to Synergy base on the peak and off-peak margin values 'availability payment' calculation used to compensate Synergy for the provision of spinning reserve. AEMO's hypothetical market clearing outcomes will then be applied as fixed inputs into licenced PLEXOS software, which will then be used to produce synthetic total generation cost and total emissions for the scenario.

1.3 Cash flow calculations

Table 1 below provides an overview of the valuation method specification, which lists each operational cash flow category for each of four value distribution lenses: the gentailer lens, the aggregator lens, the customer lens, and the network operator lens. Note that in most cases the gentailer will also be a customer's aggregator, in which case the finder's fee can be considered an internal transfer payment.

Table 1: Overview of the valuation method specification by value distribution lenses

Lens	Operating value in each half hour interval =
Gentailer	Market operating profit difference + NSS payment + Customer bill difference - Retail MBC difference – Finder's fee
Aggregator	Finder's fee - VPP incentive
Customer	VPP incentive - Customer bill difference
Network operator	Network bill difference - NSS payment

The terms in Table 1 are defined as follows:

- **Market operating profit difference** - the value obtained from orchestrating a customer's DER across different markets.
- **NSS payment –** the payment that the network operator makes to the gentailer for the provision of a network support service.
- **Customer bill difference** - the change in a customer's retail electricity bill compared to the base case. A positive bill difference corresponds to an increase in bill value for the customer in the orchestration case.
- **Retail market-based costs (MBC) difference** - the indicative change in MBC paid by the gentailer's retail business for a customer compared to the base case, a positive difference indicating a higher MBC under the orchestration case than under the non-orchestration

case (note that the network bill difference defined below is a component of the MBC difference).

- **Finder's fee** - an amount paid on an operational cash flow basis by the gentailer to an aggregator for providing DER assets to orchestrate (assumes an "aggregator of aggregator" type arrangement).
- **VPP incentive** - the amount of money paid on an operational cash flow basis to the DER owning customer to participate in the VPP
- **Network bill difference** - the change in the gentailer's network bill compared to the base case. A positive network bill difference corresponds to an increase in bill value for the gentailer in the orchestration case.

2 Background

The uptake of rooftop solar in Western Australia has increased rapidly from less than one thousand systems in 2007 to about one in three households having installed the technology by 2022, equating to ~1.7 gigawatts of passive, renewable energy, representing the largest source of generation capacity in the South West Interconnected System (SWIS).

The continuing growth in DER on the SWIS presents a range of physical challenges for the market operator, the network operator and providers of ESS in the market. While DER has the potential to deliver significant financial and environmental benefits to the community, a high penetration of unmanaged customer rooftop solar capacity poses a risk to the stability of the power system at times of low system demand. In the SWIS, this risk is highest on mild sunny days when air conditioning load is low but solar generation is high. AEMO anticipates that by 2024, power system operational conditions are likely to become insecure unless new mechanisms to address system security risk are implemented.[1]

2.1 The Project Symphony pilot

The overall vision for Project Symphony (the pilot) is to progress toward a future where the integration and participation of DER in wholesale and network service markets supports a safer, more reliable, lower carbon and more efficient electricity system.

Project Symphony will be delivered by Western Power in collaboration with Synergy, AEMO and Energy Policy WA (EPWA). The pilot will recruit a minimum of 900 DER assets from approximately 500 customers to form a VPP in Southern River, south east of Perth, with a target mix as follows:

- Generation management of rooftop solar (~1,500 kW residential and 200 kW commercial).
- HVAC control (~900 kW residential).
- Hot water control (~25 kW residential).
- Behind the meter storage (~850 kW residential and ~550 kW commercial).

By piloting a version of the Open Energy Networks (OpEN) hybrid model, which defines roles and responsibilities for transitioning to a two-way power grid, the pilot aims to understand how the opportunities and challenges of increasing DER can be addressed through better integration with the existing electricity system. Figure 2 below provides a conceptual view of the model and how each participant's technology platform will interact.

The hybrid model outlines three key roles that Project Symphony participants will be required to fulfill:

- Western Power - the distribution systems operator (DSO).
- Synergy - the DER aggregator.
- AEMO - the distribution market operator (DMO).

1 AEMO, Renewable-energy-integration: SWIS update.

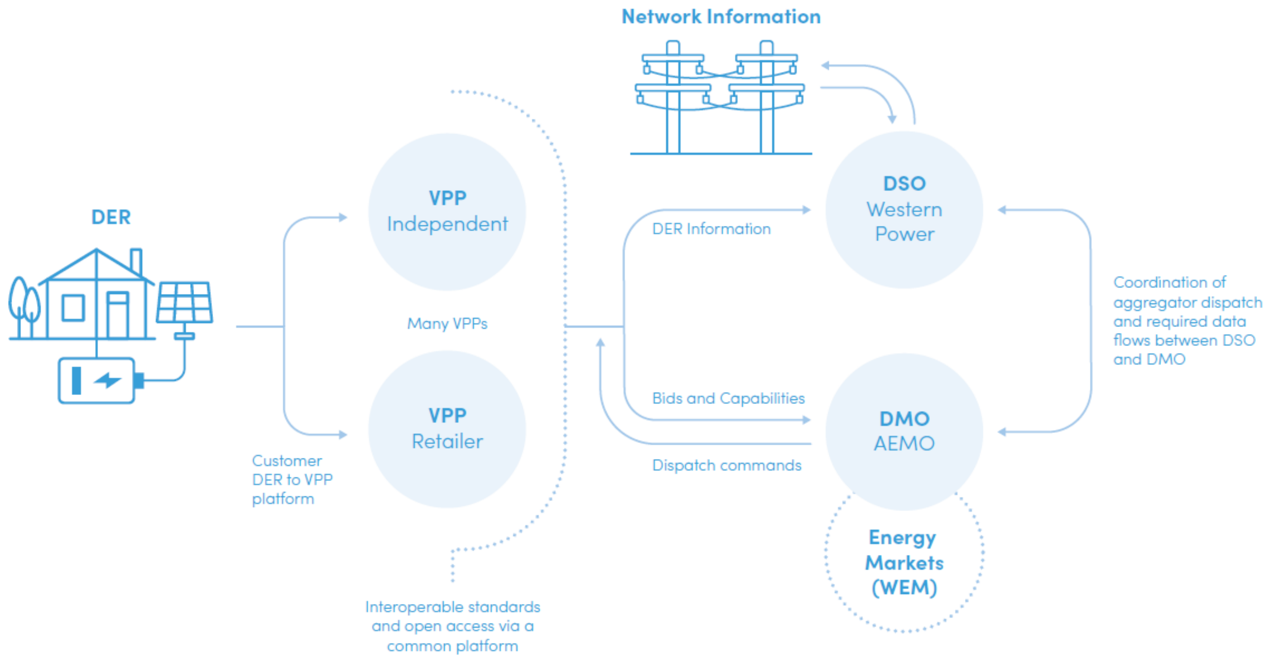


Figure 2: A possible DSO/DMO model for Western Australia

An additional role is that of third-party aggregators with existing assets and customer relationships, which Synergy will onboard and interface with Synergy's aggregation platform to access the wholesale market and broader value chain. This arrangement will enable third-parties to test new business models while leveraging the Synergy platform developed through Project Symphony.

Each pilot partner will be required to build and test separate platforms that, when integrated, will create a cohesive system for managing DER resources from end-to-end in support of a safe, reliable, and cost-effective electricity system, as follows:

- A DSO platform will be developed by Western Power to publish Dynamic Operating Envelopes (DOEs) at prescribed intervals to ensure DER output does not cause network voltage to rise above acceptable limits, aimed at maximising the renewable energy (predominantly rooftop solar) hosting capacity at any given time on the distribution network.
- A market or DMO platform will be developed by AEMO to allow aggregated DER assets to participate in the wholesale market.
- An aggregator platform will be developed by Synergy to aggregate, optimise and centrally control DER assets to deliver a range of wholesale market, network and pre-emergency DER management services.

As part of Project Symphony's test and learn workstreams, AEMO and Synergy will develop market simulation tools to demonstrate that the framework can be efficiently integrated into a mainstream model for DER orchestration in the Western Australian Wholesale Electricity Market (WEM). In building and piloting the three platforms and market simulation environment, the pilot's participants will conduct a range of technical tests, collating learnings that can be used to evolve the hybrid model and inform policy and legislative requirements to support implementation.

The end-to-end solution will demonstrate value via four primary use case scenarios:

1. **Wholesale energy services**, a market for bulk energy that is cleared by AEMO's dispatch engine to determine the least-cost allocation of generation and load to meet system demand.
2. **Network support services (NSS)**, a contracted service provided by a market participant to the network operator/DSO (Western Power) to help manage localised network constraints.
3. **Constrain to zero**, a pre-emergency service provided by a VPP to the market operator to constrain energy output from DER to zero export (net) or zero output (gross).
4. **Contingency raise ESS**, a market-provided response to a locally detected frequency deviation to help restore (raise) frequency to an acceptable level in the case of a 'contingency event' such as the sudden loss of a large generator or sudden surge in load.

Two secondary use case scenarios will be developed and tested should time, resources and budget permit, these being:

1. **Contingency lower ESS**, a market-provided response to a locally detected frequency deviation to help restore (lower) frequency to an acceptable level in the case of a 'contingency event' such as a sudden surge in supply or a sudden drop in demand.
2. **Regulation raise ESS and regulation lower ESS**, a market-provided response to automatic generation control signals to correct for small deviations in frequency during a dispatch interval.

Project Symphony's test and learn workstreams will also assess the commercial and customer experience outcomes that will be critical to the long-term viability of future VPP's at scale. To this end, a set of tools will be developed to estimate the cash flows - arising from VPP operation during the pilot period - between Synergy, the network, the DER aggregator and end-use customers. Using these tools, pilot Symphony's test and learn workstreams will endeavour to identify and measure both real and simulated cash flows associated with each of the pilot's primary use case scenarios.

A key challenge for estimating the value streams created by the Project Symphony VPP is that it will be conducted as an 'off-market' pilot under future market design assumptions, meaning that its DER assets will be dispatched in response to simulated market-clearing outcomes rather than as a result of actual market participation. This adds complexity to the analytical task of distinguishing between the costs and benefits attributable to DER orchestration and those that would occur in the absence of DER orchestration.

3 Purpose

This paper is the ARENA deliverable for Project Symphony work package (WP) 2.3, the purpose of which is to:

- Present a set of computational methods to value the operating cash flows associated with the pilot's DER assets under orchestration.
- Describe, at a high level, the techno-economic simulation tools that will be developed to determine the actual value of DER services that will be deployed or integrated through the pilot.

- Advance knowledge in the field of DER services valuation by helping to fill a public information gap on methods that may be employed to estimate the operational cashflows of VPPs under real world conditions.

3.1 Relationship with other Project Symphony work packages

This work package will leverage Project Symphony WP 2.1, the DER Services Report[2], and the use of the capability developed will be required for WP 8.3, the Cost-Benefit Analysis Report.

4 High-level design

The architectural design of the DER services valuation approach to be detailed in the following sections is summarised and illustrated by Figure 3 below. At a high level, the approach transforms half-hourly market data inputs to a set of modelling outcomes to be reported to the Project Symphony partners, by combining observed DER load and generation control data with market simulation and customer baselining estimation techniques, and by applying a set of pre-defined formulae to evaluate and compare the cash flows associated with the pilot. Key components of the framework include an aggregation platform to provide DER asset data and to simulate a customer base case (see Section 5 below), market simulation tools to support market clearing and generation cost simulations (see Section 6 below), and a set of bespoke algorithms to quantify cash flows and allocate them to pilot participant groups (see Section 7 below).

Figure 3: High-level architectural design of the DER services valuation approach

Unlike WP 2.1, the DER Services Report, and WP 8.3, the Cost Benefit Analysis Report, WP 2.3 is not a cost benefit analysis, as it defines value:

- In financial rather than economic terms
- Over an operational timeframe rather than an investment timeframe
- With a focus on allocating cash flows between parties, and therefore on developing an understanding of the value of the VPP from the perspective of each party.

A financial lens is appropriate, as this will allow the commercial viability of a VPP to be assessed, which is not the primary focus of a cost benefit analysis, although the data generated by WP 2.3 will be useful as a cost benefit analysis input.

As Project Symphony is an off-market pilot, the methods developed in WP 2.3 are aimed at estimating cash flows as inferred values rather than observed values. Reported outcomes are framed as a comparison between the operating cash flows that would occur under DER orchestration

[2] Work Package 2.1, the DER Services Report, produced by Synergy, delivered to ARENA February 2022

and participation in markets, to those that would occur under an assumed non-orchestration base case.

5 Customer base case

As discussed in Section 2.1 and Section 4 above, an assessment of the value of orchestrating a device as part of the Project Symphony VPP requires an estimation of how that device would have been operated if it were not part of the VPP. For the purposes of modelling, a standardised capability built into Enabla's Concerto aggregation platform procured by Synergy will provide the methods, outlined in the following subsections, to estimate customer loads and battery utilisation in the absence of a VPP orchestration 'event' (i.e., the 'non-orchestration base case'). The aggregation platform will calculate the asset baseline (ABL) load or generation for each asset on a near real-time basis during an event and make it visually available in the software user interface accessible to Synergy.

Calculation of the ABL for customer photovoltaics assets that may be subject to constrained output by the VPP during an event period is not provided by the platform - a tool developed by Synergy will be used to estimate this customer base case component.

The following definitions apply in the subsections that follow:

- **Event period -** one or more consecutive hours when an event is active.
- **Calculation period –** each clock-hour that an event period overlaps (e.g., for an event period between 9:50 am and 11:20 am the calculated period will be for the clock-hours 9 am to 10 am, 10 am to 11 am, 11 am to 12 pm).
- **Event day** – a day on which an event was called during an event period.

5.1 Pool pump load and hot water system load baseline

The following ABL calculation will be applied to each managed pool pump and hot water system asset that is subject to orchestration during an event period:

- The five most recent 'similar days' are defined as:
    - The five weekdays prior to the event day that are not holidays or event days, for events falling on weekdays
    - The five Saturdays prior to the event day that are not holidays or event days, for events falling on Saturdays
    - The five Sundays or holidays prior to the event day that are not other event days, for events falling on Sundays and holidays.
- Of those five 'similar days', the three days with the highest maximum kW load for the asset for an hour of the day upon which an analysed event was run are selected as the baseline days.
- An ABL will be calculated for each clock-hour over a calculation period as the mean kW asset load for each clock-hour on each of the three days selected.

Mathematically:

- Define $h \in \{1,2,\ldots,23,24\}$ as the set of clock-hours in a day

- Let $\{y_{1,h}, \dots, y_{5,h}\}$ be an ordered list of descending asset load values occurring during clock-hour h of the five most recent 'similar days' as defined above
- The ABL load, ABL_h, for a trading interval occurring during calculation hour h of the event day, is then given by:

$$ABL_h = \frac{y_{1,h} + y_{2,h} + y_{3,h}}{3}$$

5.2 Air conditioner load baseline

The ABL calculation for air conditioners will be as per the pool pump and hot water system ABL calculation listed in Section 5.1 above, after making the following 'weather' adjustment:

- An 'offset factor' will be applied to the ABL value to normalise to the loading conditions observed on the day of the event, provided that the kW observed during the hour prior to the event start time is higher than the simple mean of the corresponding hour on the three baseline days.
- If the loading conditions observed on the day of the event would result in a reduction of the non-weather adjusted ABL, then the offset factor will not be applied.

Mathematically, expanding on the notation given in Section 5.1 above:

- Let $y_{0,h-1}$ denote the asset load value occurring in the hour prior to the event hour h of the relevant event day

The offset factor, OF_h, for a trading interval occurring during hour h of the event day $d = 0$, is given by:

$$OF_h = \begin{cases} \dfrac{3 \cdot y_{0,h-1}}{y_{1,h-1} + y_{2,h-1} + y_{3,h-1}} & \text{if } y_{0,h-1} > \dfrac{y_{1,h-1} + y_{2,h-1} + y_{3,h-1}}{3} \\ 1 & \text{otherwise} \end{cases}$$

- The ABL load, ABL_h, for a trading interval occurring during hour h of the event day, is given by:

$$ABL_h = \frac{y_{1,h} + y_{2,h} + y_{3,h}}{3} \cdot OF_h$$

5.3 Photovoltaic baseline

The following ABL calculation will be applied to each managed photovoltaic system asset that is subject to constrained output during an event period:

- Whenever the observed inverter output is below the constrained inverter setpoint output level resulting from solar curtailment by the VPP, the ABL is equal to the observed inverter output

- Otherwise, the ABL is determined by linear extrapolation between the inverter output recorded immediately prior to the start of the event period (SOP) and that recorded immediately following the end of the event period (EOP) (see Figure 4 below)
- A final check will be made that the ABL does not result in a breach of the maximum site export limit (e.g., due to dynamic operating envelopes), i.e., the ABL will be adjusted downwards to ensure site exports remain within site export limits.

It should be noted that this approach will ignore any impact of changing cloud cover that may occur between the SOP and the EOP, unless it causes the observed inverter output to fall below the inverter set point constraint.

Mathematically, the instantaneous baseline inverter output value at time t, $f(t)$, is defined as

$$f(t) = \begin{cases} Z_1 + s \cdot (t - T_1) & \text{if } z(t) \geq ISP - TOL \\ z(t) & \text{otherwise} \end{cases}$$

$$s = \frac{Z_2 - Z_1}{T_2 - T_1}, \qquad T_1 \leq t \leq T_2, \qquad z(t) \leq ISP, \qquad TOL > 0$$

Where:

- Z_1 is inverter output value recorded immediately prior to the SOP at time T_1
- Z_2 is inverter output value recorded immediately following the EOP time T_2
- ISP is the inverter setpoint constraint
- TOL is a pre-defined tolerance level that allows for small deviations between the constrained inverter output and the set point constraint
- $z(t)$ is the observed inverter output value at time t

The ABL generation, ABL_h, in average kW over a time interval $[a, b]$ that corresponds to hour h of the event day, can be estimated by the integral:

$$ABL_h = \frac{1}{b - a} \cdot \int_a^b f(t)\, dt$$

Figure 4 below provides an illustrative example of how the ABL_h value can be calculated from the shaded area under curve $f(t)$ between time a and time b, which in turn is derived through linear extrapolation between the SOP point (T_1, Z_1) and the EOP point (T_2, Z_2).

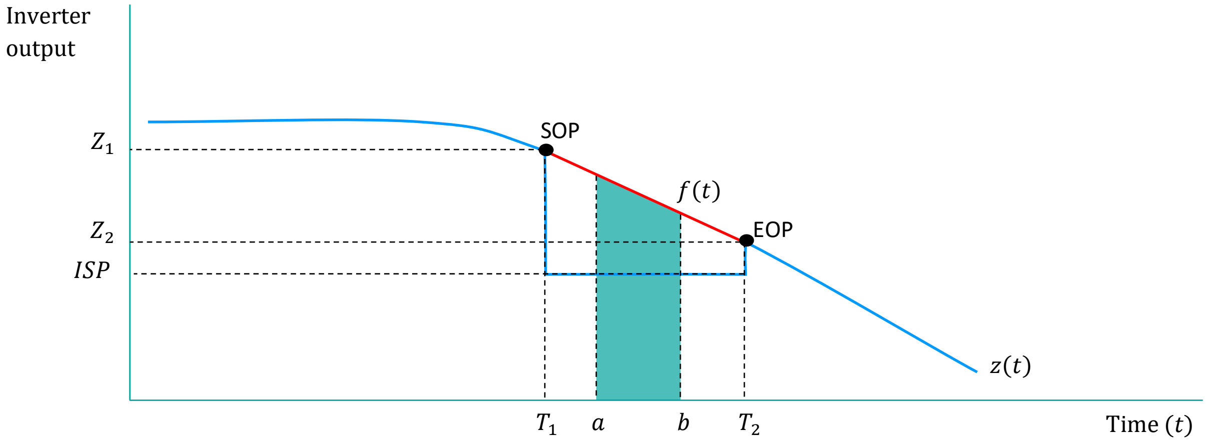
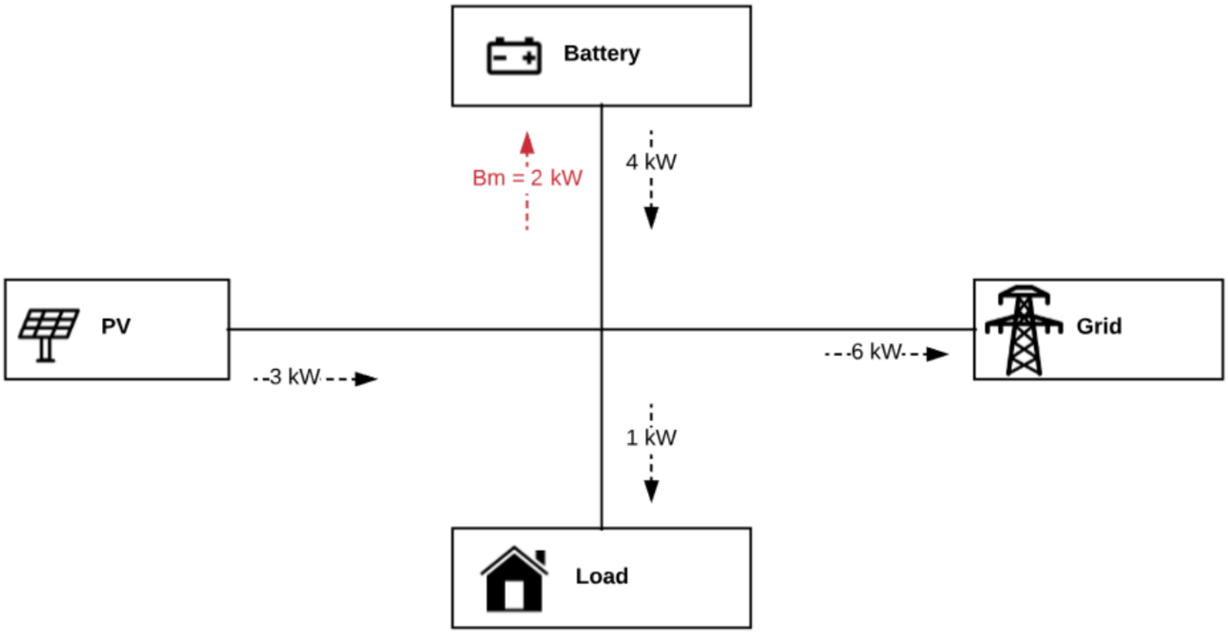


Figure 4: Illustrative example of the photovoltaics ABL estimation method using linear extrapolation

5.4 Battery baseline

Determination of the battery baseline for the next orchestration interval is based upon a calculation of what the battery would have been doing if it were in self-consumption mode, rather than being subjected to orchestration, resulting in a grid net export of zero. To determine what the power output of the battery would have been under the self-consumption assumption, the home load is calculated as shown in the first equation in Figure 5 below. Next, the battery charge/discharge that would have resulted in a net export of zero kilowatts (kW) is calculated, as shown in the second equation in Figure 5 below. The baseline calculation then continues according to binding checks on battery state of charge (SoC) and roundtrip efficiencies as described by the following procedure:

- The battery SoC is determined immediately prior to the first interval of an orchestration event and a forecast SoC at the end of the event. Following each control interval, a new forecast SoC will be calculated, on the basis of the following steps:
    1. Based on measured battery net discharge, B, photovoltaic output, P, and grid net exports, G, calculate the current house load, L, i.e, $L = G - B - P,\ L \leq 0$.
    2. Model the battery net discharge, B_m, assuming $G = 0$, i.e., $B_m = -L - P$
    3. Check binding of the forecast SoC on empty or full battery
    4. Check binding on B_m on maximum charge or discharge power and constrain back to bounds (assign to B_m)
    5. Check binding on maximum site export limit (i.e., due to dynamic operating envelopes)
    6. Set final battery power B_m considering a configured system efficiency (inverter efficiency)
    7. Increment forecast SoC on basis of B_m
    8. Account for system losses (inverter round trip efficiency)
- The battery ABL is given by B_m.



$$L = -B - P + G = -4 - 3 + 6 = -1 \quad \gg 1\ kW\ house\ Load$$
$$B_m = -L - P = -(-1) - 3 = -2 \quad \gg 2\ kW\ charging$$

Figure 5: Illustrative example of calculating the ABL power output of a battery under a self-consumption assumption

6 Market simulation approach

Significant wholesale market design changes for the SWIS are planned to come into effect shortly after completion of the term of the Project Symphony pilot. To simulate and test how features of the anticipated market design may affect future VPP operations, Project Symphony has been established as an ‘off-market’ pilot, meaning that VPP assets will not be bid or offered into the real wholesale market. Instead, market simulation will be conducted, allowing VPP assets to be dispatched as if they had been bid and offered into the real wholesale market under a future market design scenario. As such, market price and dispatch quantity outcomes observed in the real markets will not reflect the orchestration case nor the non-orchestration case. This is because, for the:

- **Non-orchestration case**, the DER assets would likely have been operated differently to how they will be operated in the pilot, resulting in a different operational demand outcome to that observed for the actual wholesale market.
- **Orchestration case**, the DER assets will be offered into the wholesale market, resulting in a different operational supply outcome to that observed for the actual wholesale market.

Therefore, estimation of VPP cashflows under the non-orchestration and the orchestration cases will both rely on simulated market outcomes.

6.1 Energy market clearing simulation

For each trading interval, AEMO will conduct a market clearing simulation by adjusting the market’s balancing merit order and operational demand for the operation of the VPP. The outcomes of the market clearing simulation will be provided by AEMO to Synergy on a post-trading day basis. At a high-level, the following process will be applied:

- VPP dispatch in the energy market will be based on AEMO's latest balancing price forecast and Synergy's hypothetical market submission for the VPP, comprising bids and offers made up of price-quantity pairs.
- Simulated market outcomes comprising the energy market price, the market clearing quantity and the Synergy portfolio dispatch quantity, will be solved by adjusting the balancing merit order offer stack and operational demand for each trading interval, as follows:
  - **Orchestration case**. The VPP's simulated price-quantity offer pairs submitted by Synergy to AEMO as part of the energy market use case scenario will be added to the balancing merit order data to generate a new offer stack. The new offer stack will be further adjusted to account for the fact that any provision of contingency raise by the VPP that reduces the amount of contingency raise required from other resources. The operational demand will be adjusted to account for the difference between the actual VPP imports/exports and the customer base case calculations described in Section 5 above.
  - **Non-orchestration case**. Operational load will be adjusted to reflect the customer base case calculations described in Section 5 above - Synergy will provide AEMO with an input to make this adjustment. The offer stack will remain unadjusted.

Table 2 below summarises the market clearing simulation approach.

Table 2: Energy market clearing simulation approach summary

Orchestration case:	Non-orchestration case:
• Get balancing merit order data used for market clearing	• Get operational demand and market submission data used for market clearing
• Adjust most recent forecast of operational demand to account for the difference between the actual VPP imports/exports and the customer base case imports/exports (Synergy provides)	• Assume the most recent forecast of operational demand incorporates VPP customer base case behaviour.
• Add simulated VPP price-quantity offer pairs to the balancing merit order data to generate a new supply stack and use bids to generate stepped demand curve where relevant	• Calculate the simulated market clearing prices and quantities on the basis of forecast demand and actual market submission data.
• Modify the offer stack to account for any provision of contingency raise by the VPP that reduces the amount of contingency raise required from other resources (Synergy provides)	
• Use this data to calculate simulated market clearing prices and quantities for orchestration case	

Figure 6 below provides an illustrative example of a market simulation outcome where it is assumed the non-orchestrated demand is consistent with AEMO's latest demand forecast. The market clearing outcomes for the orchestration and non-orchestration cases are both likely to differ from that observed in the actual market. To obtain the market clearing outcome for the orchestration case, an adjustment is made to the 'actual' submitted prices (represented by the thin blue offer stack) by adding the red VPP price-quantity offer to the balancing merit order. This generates a new offer stack that departs from the 'actual' offer stack to follow the red and green price-quantity steps to the right of the VPP offer. The orchestration case market clearing outcome is obtained at the point of intersection between this new offer stack and a level of demand adjusted to account for the difference between the actual VPP imports/exports and the customer base case imports/exports. The non-orchestration case market clearing outcome is obtained at the point of intersection of the unadjusted offer stack and a level of demand that is adjusted to reflect the customer base case. A summary of the outcomes for this example is provided in Table 3 below.

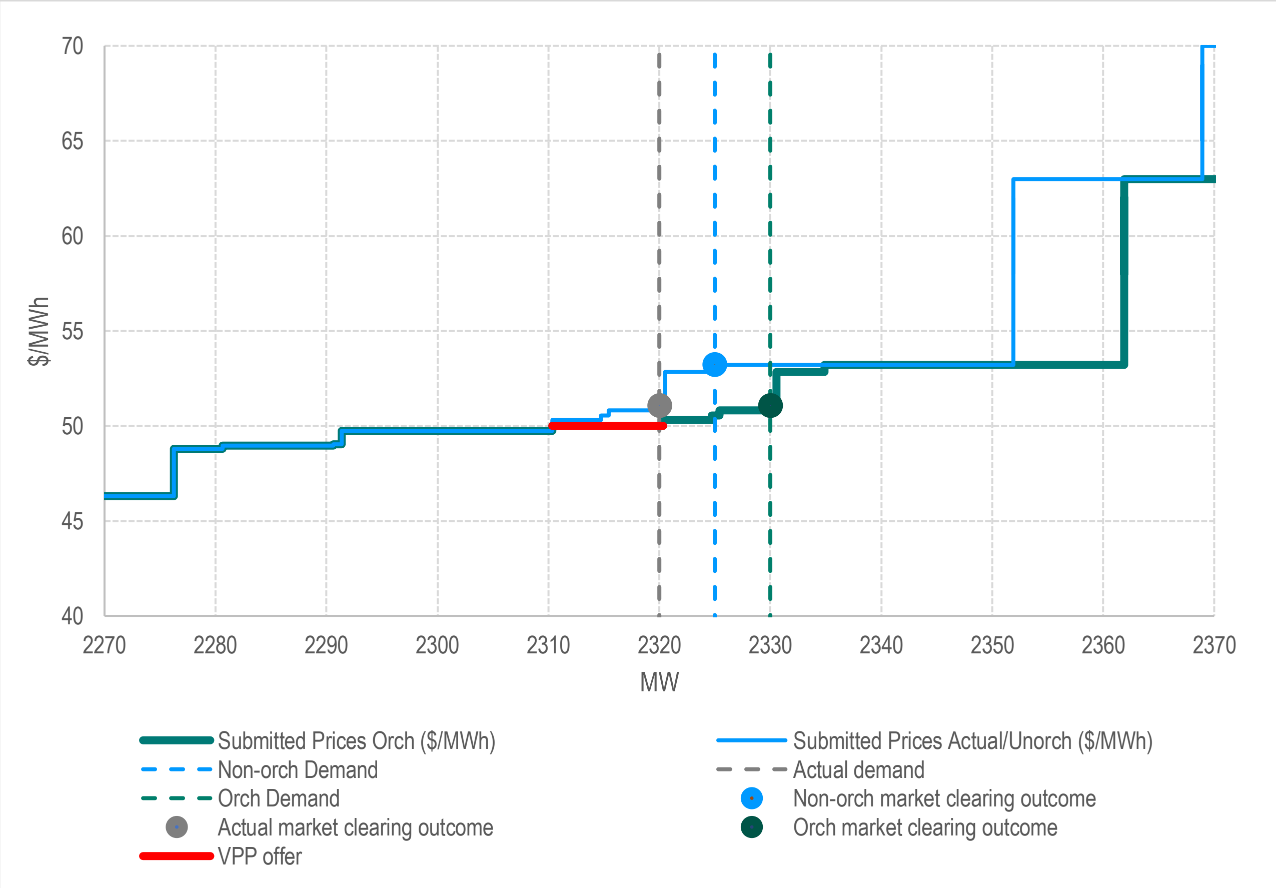


Figure 6: Illustrative example of a market simulation outcome

Table 3: Summary of the outcomes for the market simulation example depicted in Figure 6

	Orchestration case	Non-orchestration case
Quantity	As per the most recent forecast of plus or minus a quantity that accounts for the difference between the actual VPP imports/exports and the customer base case imports/exports.	As per the most recent forecast of demand for the trading interval.
Price	The intersection between the simulated offer stack and the calculated quantity.	The intersection between the forecast offer stack in the actual market and the calculated quantity.

6.2 ESS contingency raise price simulation

AEMO will also provide an ESS contingency raise price proxy to Synergy as part of the Project Symphony pilot. This task has been complicated by recent delays to the implementation of the reforms of the wholesale market, which will result in there being no contingency raise market to observe for the term of the pilot. This challenge will be overcome by using the peak and off-peak margin values 'availability payment' calculation that is currently used to compensate Synergy for the provision of spinning reserve.

The formula for the availability payment is:

$$a_t = \frac{1}{2} \cdot m \cdot \max(0, p_t) \cdot q_t$$

where:

- a_t = the availability payment for interval t
- m = the margin value
- p_t = the forecast balancing price for interval t
- q_t = the spinning reserve quantity for interval t.

The ESS contingency raise price proxy will thus be calculated as the term $\frac{1}{2} \cdot m \cdot \max(0, p_t)$, which is effectively the spinning reserve price in the availably payment formula above.

A margin value of 12.6 percent for peak intervals and 23.2 percent for off-peak intervals will be applied for the 2021/22 financial year, consistent with the ERA's most recent ancillary service costs determination.[3]

6.3 Synergy generation cost and emissions simulation

Synergy currently offers its generation into the energy market as a single portfolio, rather than being required to offer into the market by facility or power station. Recent delays to the reform of the wholesale market means that this arrangement will remain in place for the term of the pilot. Consequently, while AEMO's simulation of the market will estimate Synergy's portfolio dispatch quantity under the orchestration case and the non-orchestration case, AEMO's simulation will not identify which of Synergy's generation units are dispatched into the market. This will be overcome by applying AEMO's hypothetical market clearing outcomes as fixed inputs into licenced PLEXOS software, which will then be used to produce synthetic total generation cost and total emissions outcomes for the scenario.

7 Valuation method specification by cash flow category

As discussed in the preceding sections, the valuation methods specified in WP 2.3 are focused on measuring operating cashflows associated with the Project Symphony pilot. Operating cash flows are defined as the amount of cash a business or a customer group receives or expends due to the operation of VPP assets over a trading interval. Table 4 below provides an overview of the valuation method specification, which lists each cash flow category for each of four value distribution lenses: the gentailer lens, the aggregator lens, the customer lens, and the network operator lens. Note that

[3] Economic Regulation Authority, Ancillary service costs: Spinning reserve, load rejection reserve and system restart costs (Margin values and Cost_LR) for 2021/22 Determination, 31 March 2021.

in most cases the gentailer will also be a customer's aggregator, in which case the finder's fee can be considered internal transfer payment.

Table 4: Overview of the valuation method specification by value distribution lenses

Lens	Operating value in each half hour interval =
Gentailer	Market operating profit difference + NSS payment + Customer bill difference - Retail MBC difference – Finder's fee
Aggregator	Finder's fee - VPP incentive
Customer	VPP incentive - Customer bill difference
Network operator	Network bill difference - NSS payment

The terms in Table 4 are defined as follows:

- **Market operating profit difference** - the value obtained from orchestrating a customer's DER across different markets.
- **NSS payment –** the payment that the network operator makes to the gentailer for the provision of a network support service.
- **Customer bill difference** - the change in a customer's retail electricity bill compared to the base case. A positive bill difference corresponds to an increase in bill value for the customer in the orchestration case.
- **Retail MBC difference** - the indicative change in MBC paid by the gentailer's retail business for a customer compared to the base case, a positive difference indicating a higher MBC under the orchestration case than under the non-orchestration case (note that the network bill difference defined below is a component of the MBC difference).
- **Finder's fee** - an amount paid on an operational cash flow basis by the gentailer to an aggregator for providing DER assets to orchestrate (assumes an "aggregator of aggregator" type arrangement).
- **VPP incentive** - the amount of money paid on an operational cash flow basis to the DER owning customer to participate in the VPP.
- **Network bill difference** - the change in the gentailer's network bill compared to the base case. A positive network bill difference corresponds to an increase in bill value for the gentailer in the orchestration case.

The formulae provided in Table 4 are further decomposed in the following subsections.

7.1 Market operating profit difference

The market operating profit difference, ΔMOP, in trading interval t is given by:

$$\Delta MOP = \Delta WMR + \Delta WMC,$$

where

$$\Delta WMR = \Delta EMR + \Delta LGC + \Delta AP + \Delta CR$$

$$\Delta EMR = WP_O \cdot \sum_i \max(q_{iO}, 0) - WP_B \cdot \sum_i \max(q_{iB}, 0)$$

$$\Delta LGC = LGC_O - LGC_B$$

$$\Delta AP = \frac{1}{2} \cdot m \cdot \left(\max(WP_O, 0) - \max(WP_B, 0)\right) \cdot S$$

$$\Delta CR = \begin{cases} \frac{CP}{8 \cdot D} \cdot \mathrm{K}_i - RF_i & \text{if } t \in T \\ 0 & \text{otherwise} \end{cases}$$

$$\Delta WMC = \left(GC_O - WP_O \cdot \sum_i \min(q_{iO}, 0)\right) - \left(GC_B - WP_B \cdot \sum_i \min(q_{iB}, 0)\right)$$

The notation Σ_i indicates summation across all the gentailer's facilities, including VPP facilities.

The following definitions apply:

ΔWMR	is the gentailer's simulated wholesale market revenue difference in trading interval t
ΔWMC	is the gentailer's simulated wholesale market cost difference in trading interval t
ΔEMR	is the gentailer's simulated energy market revenue difference in trading interval t
ΔLGC	is the gentailer's simulated large scale generation certificate revenue difference in trading interval t
LGC_O	is the gentailer's simulated large scale generation certificate revenue difference in trading interval t under the orchestration case
LGC_B	is the gentailer's simulated large scale generation certificate revenue difference in trading interval t under the non-orchestration base case
ΔAP	is the gentailer's simulated spinning reserve availability payment difference in trading interval t
ΔCR	is the gentailer's simulated capacity revenue difference in trading interval t
WP_O	is the simulated wholesale energy price in \$/MWh in trading interval t under the orchestration case
WP_B	is the simulated wholesale energy price in \$/MWh in trading interval t under the non-orchestration base case
q_{iO}	is facility i's simulated clearing energy quantity in MWh for trading interval t under the orchestration case, where $q_{iO} > 0$ implies net exports of energy and $q_{iO} < 0$ implies net imports of energy

q_{iB} is facility i's simulated clearing energy quantity in MWh for trading interval t under the non-orchestration base case, where $q_{iB} > 0$ implies net exports of energy and $q_{iB} < 0$ implies net imports of energy

m is the margin value for trading interval t

S is the simulated spinning reserve quantity for trading interval t

CP is the capacity price in $/MW/year

D is the number of days in the year

K_i is the amount of capacity credits allocated to facility i in trading interval t, based on the output the facility can sustain over four consecutive hours

RF_i is any refund facility i must pay to AEMO in the event it fails to comply with its reserve capacity obligations applicable to trading interval t, calculated in accordance with clause 4.26.1 of the WEM Rules

T is the set of intervals classified as electric storage resource obligation intervals for the relevant trading day, as defined in the WEM Rules

GC_O is the gentailer's simulated generation costs in trading interval t under the orchestration case

GC_B is the gentailer's simulated generation costs in trading interval t under the non-orchestration base case

7.2 NSS payment

The NSS payment will be the subject of contractual negotiation over the coming months, and so cannot be written as a precise mathematical expression at the time of this publication.

7.3 VPP incentive

The VPP incentive for Synergy aggregated customers will be an upfront fixed payment and so is not considered a cash flow associated with the operation of VPP assets over a trading interval. It is possible that third-party aggregators will offer a VPP incentive on an operational (e.g., per-event) basis, in which case the VPP incentive will be formulated as an operating cash flow. Third-party aggregation arrangements will be the subject of contractual negotiation over the coming months, and so cannot be written as a precise mathematical expression at the time of this publication.

7.4 Customer bill difference

The customer bill difference, ΔCB, in trading interval t is given by:

$$\Delta CB = CB_O - CB_B,$$

where

$$CB_O = -\sum_i \left(RP_i \cdot \min(x_{iO}, 0) + FIT_i \cdot \max(x_{iO}, 0)\right)$$

$$CB_B = -\sum_i \left(RP_i \cdot \min(x_{iB}, 0) + FIT_i \cdot \max(x_{iB}, 0)\right)$$

The notation Σ_i indicates summation across all customers participating in the pilot.

The following definitions apply:

- CB_O is the sum of all participating customers' bill values under the orchestration case, allocated to trading interval t
- CB_B is the sum of all participating customers' bill values value under the base case, allocated to trading interval t
- RP_i is the $/kWh component of customer i's retail tariff in trading interval t
- FIT_i is the $/kWh component of customer i's feed-in-tariff in trading interval t, where the feed-in-tariff reflects the appropriate REBS or DEBS rate, depending on the customer
- x_{iO} is customer i's observed meter reading in kWh for trading interval t, where $x_O > 0$ implies net exports of energy and $x_O < 0$ implies net imports of energy
- x_{iB} is customer i's estimated base case meter reading in kWh for trading interval t, where $x_B > 0$ implies net exports of energy and $x_B < 0$ implies net imports of energy

7.5 Retail MBC difference

The retail MBC difference, $\Delta COGS$, in trading interval t is given by

$$\Delta COGS = \Delta WEC + \Delta NB + \Delta RCL + \Delta CC,$$

where

$$\Delta WEC = WEC_O - WEC_B$$

$$\Delta NB = NT_i \cdot \sum_i \left(\min(x_{iB}, 0) - \min(x_{iO}, 0)\right)$$

$$\Delta RCL = \left((LP \cdot RPP) + (SP \cdot STP)\right) \cdot \sum_i (x_{iO} - x_{iB})$$

$$\Delta CC = CC_O - CC_B$$

The following definitions apply:

- ΔWEC is the gentailer's simulated wholesale energy costs difference for its retail business in trading interval t
- WEC_O is the gentailer's simulated wholesale energy costs for its retail business in trading interval t under the orchestration case

WEC_B	is the gentailer's simulated wholesale energy costs for its retail business in trading interval t under the non-orchestration base case
ΔNB	is the network bill difference in trading interval t
NT_i	is the $/kWh component of the network tariff paid by the gentailer, allocated to customer i in trading interval t
x_{iO}	is customer i's observed meter reading in kWh for trading interval t, where $x_O > 0$ implies net exports of energy and $x_O < 0$ implies net imports of energy
x_{iB}	is customer i's estimated base case meter reading in kWh for trading interval t, where $x_B > 0$ implies net exports of energy and $x_B < 0$ implies net imports of energy
ΔRCL	is the gentailer's renewable energy certificate liability difference in trading interval t
LP	is the assumed large scale generation certificate price for the year
RPP	is the renewable power percentage for the year
SP	is the assumed small scale generation certificate price for the year
STP	is the small-scale technology percentage for the year
ΔCC	is the simulated capacity cost difference in trading interval t
CC_O	is the gentailer's simulated capacity costs for its retail business allocated to trading interval t under the orchestration case
CC_B	is the gentailer's simulated capacity costs for its retail business allocated to trading interval t under the non-orchestration base case

7.6 Finder's fee

The finder's fee payment will be the subject of contractual negotiation over the coming months, and so cannot be written as a precise mathematical expression at the time of this publication.

7.7 Network bill difference

An expression for the network bill difference is provided in Section 7.5 above.

8 Next steps

In collaboration with the project partners Synergy will develop a tool for Project Symphony based on the methodology outlined in this document which will seek to value the simulated operating cash flows across the energy system including customer, network, retail and market associated with the integration and participation of the pilot's DER assets.

It is the intent of the partners for this tool to be ready for use in advance of Project Symphony's test and learn phase which will run from 1 October 2022 to 31 March 2023. The outputs from the tool will be leveraged for Work Package 8.3, the Cost-Benefit Analysis Report, which is due to be delivered to ARENA in June 2023.

It is important to note that the methodology outlined in this document reflects the partners’ current thinking; when the tool is developed it may differ as the thinking advances through development and testing. Any material differences to this documented methodology will be highlighted in Work Package 8.3.