Project Symphony

Our energy future

Work Package 8.3

Cost Benefit Analysis and Recommendations Report

Prepared by Ernst & Young Australia

In partnership with:

western power synergy AEMO Government of Western Australia Energy Policy WA

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1. Executive Summary

The energy landscape is rapidly evolving and Western Australia (WA) is at the forefront of this transition as we accelerate towards a future with higher levels of renewable generation connected to the network and increased electrification of industry, transport, and homes. Distributed energy resources (DER) such as distributed rooftop solar photovoltaic (DPV), distributed energy storage systems (DESS), electric vehicles (EV) and controllable loads, will play an important role in this transition, creating opportunities to manage rising electricity costs and progress towards a low carbon future.

With an abundance of sunlight and space, Australia already has the highest capacity of solar photovoltaic generation installed per capita of the population in the world;[1] and in WA, over 1 in 3 households in the Southwest Interconnected System (SWIS) have a DPV system with a total installed capacity of 2.5GW, which is forecast to increase to 4.2GW by 2033.[2]

The level of penetration of DPV connected to the SWIS results in, at certain times of the year, the generation from DPV significantly contributing to meeting the operational demand for energy. Whilst this growth in DPV enables DPV owners to benefit from lower electricity bills, unmanaged DPV has the potential to disrupt the stability and reliability of the energy system, leading to higher system costs.

The SWIS and Wholesale Electricity Market (WEM) are already experiencing DER-related risks, which are beginning to manifest across the power system. Some of these risks include:

- Increased system instability due to increased DPV generation and higher capacity DPV systems.
- Localised over-voltage issues on the LV network resulting in power fluctuations, possible equipment damage and customer complaints.
- Reduced operational demand and reverse power flow issues during high solar irradiance.
- Increasing reactive power flows back to the substation from the distribution network.

Steps to mitigate this risk in the short term have been implemented, such as Emergency Solar Management (ESM) and Synergy's Solar Rewards Program, and limiting the size of DPV systems for different connection types so that is does not exceed the available capacity at the connection point.[3] In the longer-term, there are opportunities to manage the integration of DER through orchestration and in such a way that the risks to the electricity system can be appropriately managed, whilst enabling customers to install DER and enable all customers in the SWIS to benefit from the full capabilities of DER.

In recognition of the importance of managing DER integration, the WA government established the Energy Transformation Taskforce to develop an Energy Transformation Strategy and DER Roadmap for the State, designed to balance the technical, customer, and market implications of DER integration; and to ensure that the benefits and challenges of DER and large-scale renewable generation would be appropriately managed. A key deliverable of the DER Roadmap is a DER orchestration Pilot, which led to the establishment of Project Symphony.

Project Symphony is a joint ARENA and State Government-backed project, led by Western Power with the support of Synergy, the Australian Energy Market Operator (AEMO), Energy Policy WA, and university research partners. Project Symphony was delivered over a 2.5-year period and involved the recruitment of

[1] International Energy Agency, 2022. *Snapshot of global PV markets*
[2] AEMO, 2023a. *2023 Wholesale Electricity Market Electricity Statement of Opportunities*, p. 34
[3] Western Power, 2023a. *Solar connections*

over 500 customers and nearly 1,000 DER assets enrolled within a Virtual Power Plant (VPP) to demonstrate the end-to-end technical capability and value of orchestrated DER in the SWIS across four discrete test scenarios:

- Bi-Directional Energy – Balancing Market.[4]
- Network Support Services (NSS).
- Constrain to Zero (CTZ).
- Essential System Service – Contingency Reserve Raise (ESS-CRR).

The in-field Pilot component of the project was undertaken in a residential suburb approximately 20km from the Perth CBD which had already experienced a high level of DER uptake.

By extrapolating the results from Project Symphony (the Pilot), this Cost Benefit Analysis (CBA) report has been prepared to quantify the costs and benefits across the SWIS over a 10-year period for residential customers, Western Power (as the Distribution System Operator (DSO)), Synergy (as an Aggregator), AEMO (as the Distribution Market Operator (DMO)) and Third-Party Aggregators (TPAs). As such, the CBA uses the test scenarios conducted in the Pilot to determine which DER assets are used and for what service. It includes commercial elements used in the Pilot relating to provision of NSS, TPA payments made by Synergy, and the incentive and orchestration payments provided to customers. The CBA combines these with wider market considerations, such as current tariffs and system costs (e.g., minimum demand services and load following ancillary services), to determine a scaled value of the costs and benefits, comparing the costs and benefits of a base case in the absence of DER orchestration, against each of the four test scenarios. In addition to the four test scenarios, the CBA considers a Fully Orchestrated test scenario, combining the four test scenarios from the Pilot into a single test scenario and taking advantage of value stacking capabilities. No other permutations or combinations of the test scenarios were considered.

It is important to note that the costs and benefits attributed to AEMO are costs and benefits that would normally be passed on to market participants via cost recovery and distribution mechanisms. With cost recovery mechanisms falling outside the scope of the CBA, they are attributed to AEMO on a temporary basis to capture the value of scaling the Pilot to the SWIS whilst recognising that AEMO is not the final value holder. Similarly, it is recognised that Western Power's regulated revenue is also managed under its Access Arrangement, with most costs and benefits being passed on by Western Power to other users of the network.

Four modelling scenarios were considered in the CBA to reflect the variability of future conditions, and a range of net present values (NPVs) to deliver the VPP at scale across the SWIS. These modelling scenarios are *Pilot, Expected growth, High growth* and *Hyper growth*. The modelling scenarios built upon the assumptions used in the Pilot but also considered the different growth rates for DPV and battery storage in the 2023 WEM Electricity Statement of Opportunities (ESOO) and different percentages of VPP participation of DER owners in the SWIS.

Whilst a discounted cash flow (DCF) model was developed for each project stakeholder to capture the cashflows stemming from their respective role in DER orchestration, the cashflows for the Aggregator, the DSO, the DMO, residential customers and TPAs were combined to provide a net value of DER orchestration

[4] The Balancing Market and Load Following Ancillary Service (LFAS) Market were replaced by the Real-Time Market (RTM) as part of WEM reform changes implemented in October 2023. Whilst Project Symphony included the balancing market in Pilot tests, FCESS, which also forms part of the RTM, was not considered in scope, with the exception of ESS-CRR.

via an aggregated facility (such as a VPP), rather than as a collection of independent stakeholders. The combined cashflows were then used to compare each test and modelling scenario against the base case.

As Project Symphony only considered a subset of DER (DPV and DESS) used across the four test scenarios, the CBA is limited in terms of the value generated from orchestrating DER via aggregation through a VPP. The results reflect the value of orchestrating limited DER across limited value streams. Despite this, the Fully Orchestrated test scenario, where all test scenarios are delivered in concert, shows a positive NPV, suggesting significant upside if Project Symphony's solution is expanded to include other DER and value streams, and/ or achieving a reduction in costs associated with orchestrating DER over time.

The net cashflows in the Fully Orchestrated test scenario for each modelling scenario is provided in Figure 1. The net cashflows are used to illustrate the benefits of DER orchestration across multiple stakeholders on a year-on-year basis, which are then discounted over the 10-year modelling period to provide a NPV of the total investment. The combined cashflows for the DSO, DMO, aggregators and customers increase in each year for each modelling scenario, delivering a NPV of $450 million over 10 years in the *Expected growth* scenario, and a NPV ranging from $280 million to $920 million in the other modelling scenarios.

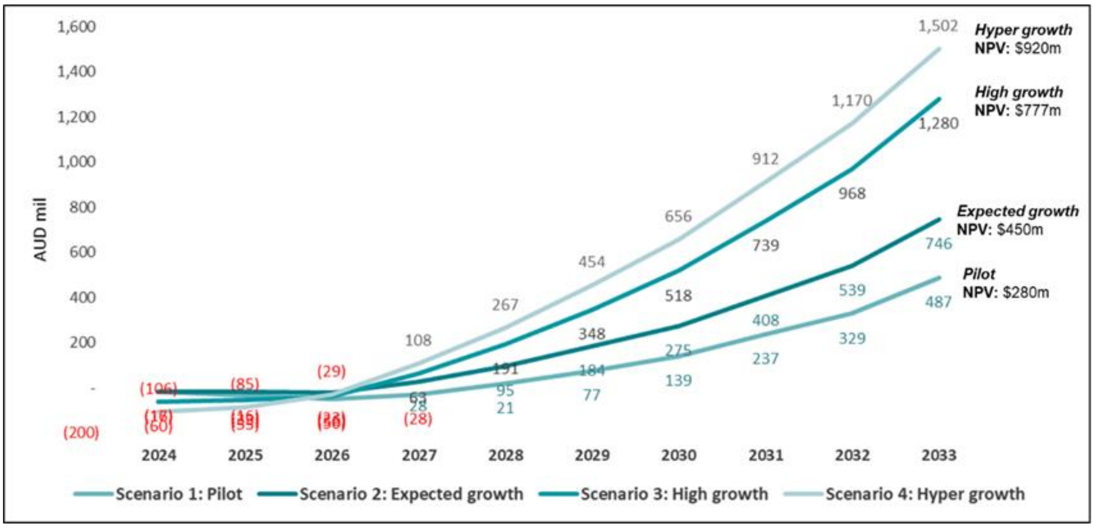

Figure 1: Combined undiscounted yearly cashflows for the Fully Orchestrated scenario

Regarding the individual test scenarios, when assessing the benefits of Project Symphony's solution under the conditions tested within the Pilot, the CBA found that there was a positive combined NPV in the Bi-directional Balancing Market under all modelling scenarios. This is driven by a reduction in system costs and the significant value of incentive and orchestration payments received by customers from Synergy. As mentioned, though the reduced system costs are attributed to AEMO, AEMO is not the final recipient of this value, with regulations and mechanisms in place to ensure it is passed on to market participants, and finally, customers. The other test scenarios (NSS, CTZ and ESS-CR), however, when considered in isolation of each other, did not result in a positive NPV. A key aspect of the NSS test scenario was NSS being undervalued in the Pilot when compared with more recent NSS values on a $/MWh basis. However, the driving difference between the Bi-directional Balancing Market test scenario and the NSS, CTZ and ESS-CR test scenarios, which contributed to the negative NPV of the latter three, is the exclusion of capabilities allowing the aggregator to sell energy generated by customer DPV into the market. This, combined with the capital expenditure required to scale the Pilot to the SWIS and subsequent ongoing operating expenditure, suggest these services when delivered in isolation of other services have insufficient return on investment. However, as technology and business capabilities mature and become more efficient and effective, a decrease in and economies of scope and scale, as well as optimised commercial arrangements, will have a significant impact on improving the overall NPV.

The Pilot sought to test the technical viability of orchestrating DER via a VPP to provide energy and energy-related services in the WEM. As such, it did not test commercial constructs, nor seek to identify the optimal commercial framework for a VPP. Rather, the customer engagement approach used in the Pilot was designed to attract customers to participate in the Pilot, and as such, the incentives and orchestration payments to customers and TPAs are not indicative of a commercially viable VPP; nor reflective of the commercial arrangements that will be used to recruit VPP participants in the future.

The purpose of the CBA is to assess the value derived from the Pilot in a scaled environment. To achieve the maximum value from DER orchestration, accelerated and targeted VPP participation will be required. As such, further analysis is recommended to develop a pricing and customer engagement strategy that is reflective of a DER aggregation market, including consideration of appropriate customer engagement models to incentivise VPP participation and equitably distribute value across participants. Reflecting the purpose of the customer engagement approach used in the Pilot, the results reveal customers as receiving a disproportionate share of value from DER orchestration to the detriment of Synergy and TPAs, both of whom experience a negative NPV. Despite customer costs increasing, the benefit customers receive from the incentive and orchestration payments far outweigh the increase in costs. Under the *Expected growth* modelling scenario, customers' electricity bills increased by $76 million, however, over the same 10-year period, customers received $1.14 billion from customer incentive and orchestration payments, which more than adequately compensates for the increase in customer energy costs. It is further noted that the increase to customer energy costs was primarily experienced by customers without a battery system, with customers owning a battery achieving a minor decrease in their energy bills as a result of participating in the VPP.

As such, though a positive NPV under the Fully Orchestrated test scenario was achieved, the distribution of value across each of the stakeholders requires further consideration. The revenue received by Synergy as the aggregator for market and non-market services, as well as increased customer bills, were outweighed by the associated costs of establishing the VPP and recruiting customers. Similarly, TPAs' costs outweighed the revenue they received from Synergy for recruiting customers. As mentioned, the commercial constructs used in the Pilot, and modelled in the CBA as a result, was designed for rapidly attracting customers to participate in the VPP in a concentrated area of the distribution network and are not sustainable. Sensitivity analysis shows alternative arrangements to recruit customers, such as incentive payments that reflect value generated by the aggregator, will have a positive impact on the aggregator's NPV and allow for greater value to be distributed to TPAs.

The CBA results broadly demonstrate that:

- A combined net positive value across all participants can be achieved when value stacking network and market services in a Fully Orchestrated DER scenario.
- The distribution of value across participants is responsive to the costs associated with developing and maintaining DER orchestration and aggregator capabilities, however, significant upside potential can be realised as technology costs reduce, business capabilities mature, and customer engagement approaches become more commercially focused.
- Increased participation of customers and their DER assets in a VPP will be a critical factor to enable the benefits of a VPP to be realised, with greater levels of participation resulting in greater value generated.
- Orchestrating DER through aggregation via a VPP substantially reduces system costs and helps alleviate local network constraints, allowing a reduction in costs to be passed through to market participants and, potentially, end-use customers.
- Further work is required to develop the commerciality of a VPP to equitably pass through the financial benefits of DER orchestration across participants and actors within a VPP, whilst not at the detriment of customers in the SWIS that do not own DER or elect not to participate in a VPP.

- The payment for providing NSS and CTZ requires further work to ensure it is priced such there is sufficient incentive for aggregators to invest in providing the service, whilst maintaining an acceptable distribution of benefits.
- Further value could be derived from the market and non-market service provided by the VPP by targeting the recruitment of battery storage in the VPP to access additional revenue streams.

Because the results in this CBA report are based on an extrapolation of the outcomes of the Pilot, it was limited to the four test scenarios and a subset of DER assets that, due to the omission or lack of statistical representation within the Pilot area, did not include large-scale battery storage that is directly integrated into the distribution network (e.g. grid connected batteries), EV charging, and controllable loads such as hot water systems and air conditioner systems. As a result, the Pilot represents a small sample of potential applications and benefits of DER orchestration that could be achieved.

Although there were limitations in the scope of Pilot and therefore the CBA, the Pilot demonstrated that DER orchestration can deliver a positive NPV when the four test scenarios are co-optimised. Furthermore, sensitivity analysis of the CBA results indicates the there are opportunities to optimise value to project participants when delivering the VPP at scale, such as:

- Developing a customer participation and engagement model that provides a compelling value proposition for customers and targets the recruitment of DER assets in the VPP in consideration of both system needs and localised network constraints.
- Transitioning to DER specific tariffs and connection agreements
- Achieving economies of scope and scale to reduce the capital and operating costs associated with DER orchestration and developing the required business capabilities to operationalise a VPP at scale
- Maximising the types and capacity of DER assets that can provide orchestration services (e.g., larger battery capacities and vehicle-to-grid EV capabilities).
- Maximising the types of energy services and markets that orchestrated DER can access.

As such, the following areas have been identified for further investigation, with corresponding recommendations to explore additional benefits of DER orchestration.

1. *Optimising commercial arrangements to distribute value equitably.*

Ref No.	Recommendation
1.1	Conduct in-depth market analysis to develop potential commercial models to scale the VPP in consideration of other VPP pilots and product offerings used in other jurisdictions.
1.2	Transition to bi-directional time-of-use network reference tariffs to provide for increased flow of energy in the network and enable increased price signalling for investors in the market.
1.3	Conduct further analysis to understand the impact of passing through avoided or deferred expenditure to customers and market participants, through reduced market participation fees and changes to network tariffs.

2. *Alternative incentives to increase customer participation in VPPs.*

Ref No.	Recommendation
2.1	Develop educational programs to provide customers with knowledge of the benefits they receive from enrolling their DER in a VPP, how their DER will be used in a VPP and the impact to their energy use, and how customers will be able to monitor VPP control of their DER *(Linked to Action 36 of the DER Roadmap.)*

2.2	Explore the social licensing and impact on customer sentiment of mandating VPP participation for different DER.
2.3	Provide finance mechanisms to reduce the up-front investment required by customers or introduce power purchase agreements, increasing accessibility of VPP participation.
2.4	Utilise build-to-rent schemes to increase VPP participation and take advantage of larger DER.
2.5	Consider mechanisms that enable renters to invest in and/ or install DER without needing to be a homeowner, increasing accessibility of VPP participation. *(This links to Action 20 of the DER Roadmap.)*
2.6	Introduce DER specific retail tariffs that enable customers to minimise energy bills via the use of DESS and flexible loads, incentivising investment in these DER, as well as VPP participation *(Linked to Action 17 of the DER Roadmap).*

3. Transition to dynamic connection contracts and enhanced use of DOEs.

Ref No.	Recommendation
3.1	Undertake additional testing and targeted recruitment of larger capacity DPV systems (e.g., > 10kW) to test DOE capabilities in managing larger systems.
3.2	Explore the use of dynamic connection agreements with customers in the WEM directly to enable DOEs outside of VPP participation and allow larger DER to be connected.
3.3	Review Western Power's basic embedded generation technical requirements document in consideration of DOEs.

4. Reducing capital and operating costs.

Ref No.	Recommendation
4.1	Target recruitment of customers on the basis of zone substations to ensure hardware costs are incurred efficiently.
4.2	Explore the use of alternative data collection equipment and approaches to decrease required capital expenditure, including the feasibility of mobile data recorders to complete compliance checks rather than continuous compliance monitoring.
4.3	Conduct in-depth whole-of-system modelling to assess the value of DER orchestration via a VPP for generation businesses, including the impact on generation emissions.
4.4	Identify key geographical areas with high penetration of DESS to maximise potential services that may be provided, with consideration given to NSS as a localised service, and adopt a targeted recruitment approach.
4.5	Include a section in the Network Opportunities Map specific to NSS and potential capacity required for different geographical areas as an investment signal to VPPs.

5. Accessing the value of DER in other energy services and markets.

Ref No.	Recommendation
5.1	Test DER capabilities to provide Contingency Reserve Lower services, Regulation services, and System Restart services, as well as capabilities to participate in the RCM, and conduct whole-of-system modelling to assess the value of a VPP orchestrating DER for use in all electricity markets in the WEM.

6. Maximising the types of DER assets that can provide orchestration services.

Ref No.	Recommendation

6.1	Develop a consistent set of connection standards and communications protocols for connecting EV charging infrastructure to the network and review the connection process to streamline connection of EV infrastructure *(Linked to Action 16 of the DER Roadmap).*
6.2	Develop EV-specific charging tariffs to incentivise investment in EV charging infrastructure in areas of the network deemed by the network operator to provide the most benefit or least cost of network augmentation *(Linked to Action 16 of the DER Roadmap).*
6.3	Test EV capabilities in a future pilot and conduct whole-of-system modelling to assess the benefits of including EV capabilities in a VPP *(Linked to Action 16 of the DER Roadmap).*
6.4	Test the capabilities of grid connected batteries in a future pilot and conduct whole-of-system modelling to assess the benefits of including these in a VPP compared to residential BTM DESS, determining an optimal asset mix.
6.5	Test air conditioner capabilities in demand management and load shifting (e.g., pre-cooling of homes) in a future pilot and conduct whole-of-system modelling to assess the benefits of including air conditioners as a flexible load in a VPP.
6.6	Ensure flexibility in customer contracts allowing customers participating in a VPP to opt-in or opt-out for each of their specific DER assets being controlled to provide each service.
6.7	Test electric hot water system capabilities in a future pilot, targeting recruitment in specific locations of the network with emerging or existing constraints to ensure successful testing regarding use for NSS, and conduct whole-of-system modelling to assess the benefits electric hot water systems can provide via a VPP.
6.8	Ensure statistically significant representation of different types of electric hot water systems in future testing and compare the value associated with each type.
6.9	Consider implementing government schemes to reduce customers' up-front cost of upgrading from a gas hot water system to an electric hot water system to increase uptake of these DER assets.

In addition to the recommendations exploring additional value of DER orchestration in the SWIS, and to continue to advance DER orchestration in the WEM, the following two areas and subsequent recommendations were identified for further consideration:

7. *Analysing the impact of a VPP from a whole-of-system perspective.*

Ref No.	Recommendation
7.1	Conduct in-depth, whole-of-system modelling, expanding on the CBA by incorporating all market participants (retailers, generators and ESS providers) in the SWIS, cost recovery mechanisms for AEMO and Western Power, and both contestable and non-contestable customers to quantify the full potential value available from Project Symphony's solution.
7.2	Compare findings from the in-depth, whole-of-system modelling in the short-term and medium-term with the short-term and medium-term Projected Assessment of System Adequacy reports published by AEMO to determine a VPP's impact on system reliability.
7.3	Utilise published measures on CO_2 emissions to quantitatively assess the impact of a VPP on emissions in the SWIS.

8. *Establishing a competitive TPA market.*

Ref No.	Recommendation
8.1	Conduct further testing of TPAs without restricting their operations, allowing them to operate as they would in a live market, with operations determined by price signals and other market powers.
8.2	Encourage the participation of TPAs in the non-contestable market, under the direction of the parent aggregator, whilst enable TPAs with the flexibility to participate in the contestable market .

2. Background

2.1 The Southwest Interconnected System

The SWIS is an isolated system consisting of electricity transmission and distribution networks and electricity generation located in the southwest of WA. It covers an area of approximately 255,000m^2 that extends from Kalbarri to Albany, and Kalgoorlie to the east. Figure 2 provides an overview of the SWIS and the communities it serves.

Figure 2: Map of the SWIS[5]

As the SWIS does not have an interconnector to the Northwest Interconnected System (NWIS) or the National Electricity Market (NEM), the operation of the SWIS needs to be self-sufficient and internally balance supply and demand for electricity.[6] As of 2023, the SWIS had approximately 20TWh of electricity being traded across its network,[7] servicing approximately 2.3 million customers[8] and a generation mix consisting of both thermal and renewable generation sources, with an increasing shift towards renewable generation and storage in line with State climate action and changing customer attitudes towards carbon emissions. Operational consumption is forecast to reach 30.3TWh by 2033, increasing at an average annual rate of 5.6%.[9]

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[5] Western Power, 2022a. *Annual Reliability and Power Quality Report for the year ended 30 June 2022*, p. 4
[6] Alexander & Blaver, 2021. *Project Symphony: Vision and Impact Pathway*
[7] AEMO, 2022a. *Wholesale Electricity Market Factsheet*
[8] Western Power, 2022b. [What We Do | Western Power | Electricity Network Operator]() (accessed 7 March 2023)
[9] AEMO, 2023a. p.5

Under the *Wholesale Energy Market Rules* (WEM Rules), there are two rule participants delegated responsibilities relating to the management of the SWIS: network operators and the system and market operator.[10] Generators and retailers are also key participants in the WEM.

Network Operators

Western Power is the largest transmission and distribution network operator in the SWIS and is responsible for ensuring residential, commercial and industrial customers can access the electricity network, as well as maintaining the safety, reliability and operation of the electricity network and supporting infrastructure. Smaller privately owned distribution and embedded networks also exist, which support private sites such as mining operations, shopping centres, retirement villages and apartments.

Western Power's capital and operating expenditure is regulated by the Economic Regulation Authority, via an access arrangement to ensure it operates at a reasonable cost and charges a fair price for its services. Under the terms of this regulatory contract, electricity tariffs (e.g., prices), are determined by the revenue that Western Power is permitted to earn each year to offset the cost or managing the network.

As a network operator, Western Power is required to maintain the technical requirements of the network and has a vested interest in understanding whether DER orchestration can optimise the utilisation of the network or defer network augmentation expenditure, through the procurement of non-network solutions such as network support services (NSS)[11] or Alternative Options Strategy (AOS).[12]

Although the WEM Rules and Electricity Network Access Code[13] already include provisions for Western Power to procure NSS and AOS respectively, further improvements are planned by Energy Policy WA (see section 2.4) through the implementation of the framework for Non-Cooptimised Essential System Services (NCESS) which will incentivise the provision and procurement of non-network services that are not already covered by existing Essential System Services (ESS). These improvements will also seek to review and modify the Access Code to clarify Western Power's obligation to publish a 10-year transmission network plan, that will support the identification of NCESS opportunities in the short to medium term, and to consider non-network solutions, which may be delivered at a lower cost compared to network augmentation.[14]

Market and System Operator

The market and system operator, the Australian Energy Market Operator (AEMO), is an independent organisation established by the Council of Australian Governments and is responsible for the oversight and operation of both the NEM and the WEM. AEMO is a not-for-profit company limited by guarantee, with its operating and capital expenditure regulated by the Economic Regulatory Authority via three-yearly allowable revenue submissions. All costs for AEMO in the WEM are recovered from market participants through fees.

AEMO is responsible under the WEM Rules for ensuring the security and reliability of the SWIS,[15] as well as operation of the WA gas and wholesale electricity markets. AEMO operates within a broader energy market governance structure, alongside the Coordinator of Energy and the Economic Regulation Authority (ERA) in Western Australia. AEMO plays an important role in Identifying, forecasting and communicating the investment needs to meet future electricity and gas demand. This includes procuring generation, storage and

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[10] *Wholesale Electricity Market (WEM) Rules 2023* (WA). c. 2.28.1
[11] *WEM Rules 2023* (WA). s. 2C.1
[12] Western Power, 2023b. [Alternative Options Strategy 2023 (westernpower.com.au)]
[13] *Electricity Networks Access Code 2004* (WA). [WALW - Electricity Networks Access Code 2004 - Home Page (legislation.wa.gov.au)]
[14] Energy Transformation Taskforce, 2021. *A Framework for Non-Cooptimised Essential Services*
[15] *WEM Rules 2023* (WA). c. 2.1A.1A

demand side capacity such that supply meets demand at all times, in the context of a rapidly decarbonising SWIS, and the increasingly important role played by DER in this mix.

In ensuring system security and reliability, AEMO is responsible for the market's provision of adequate frequency control ESS, such as Contingency Reserve Raise, and system related NCESS, such as the Minimum Demand Service, is available in the system. It also plans and administers the Reserve Capacity Mechanism (RCM) to ensure sufficient capacity is invested in and delivered to the WEM to meet peak demand.

In the event of an energy-related emergency, such as the sudden loss of a generator resulting in a significant drop in frequency in the electricity system, AEMO is responsible for restoring the system to a secure operating state as quickly as possible.[16] AEMO is also responsible for the coordination and management of emergency arrangements, working with governments, emergency services, and energy industry participants in the event of a major disruption of energy supply.

Generators, Retailers and Customers

Generators are required to register with AEMO if they wish to participate in the energy markets and are awarded capacity credits by AEMO based on their registered facility. Based on the capacity credits awarded, generators can offer energy and energy-related services to the market. Additionally, both registered and unregistered generator facilities can provide NCESS or Supplementary Reserve Capacity under a separate Supplementary Capacity Contract, which are used when other market mechanisms are deemed insufficient to maintain system security and reliability.[17]

Retailers are also required to register with AEMO as a Market Customer to participate in the energy markets, enabling them to purchase energy to serve end-user customers. The WEM Rules categorise end-user customers as contestable and non-contestable. Contestable customers are those who consume more than 50MWh of energy in a year and can be serviced by any Market Customer. Non-contestable customers are those consuming less than 50MWh in a year, capturing all residential customers and most small businesses. To mitigate the volatility of energy prices and ensure energy remains accessible for residential customers, Synergy has sole responsibility for providing retail services to non-contestable customers.[18] As both a generator and retailer, Synergy now provides 52% of the electricity traded in the WEM, as well as 55% of the contestable gas load in the industrial and commercial market.[19]

2.2 Energy trends impacting the SWIS

The energy industry is undergoing a period of rapid transformation driven by three trends:

- Decarbonisation: shifting towards cleaner, more sustainable sources of energy.
- Decentralisation: shifting from large, centralised sources of energy to the production of energy closer to its point of consumption.
- Digitisation: the increased use of technology across the energy ecosystem.[20]

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[16] AEMO, 2022b. AEMO | What we do (accessed 8 March 2023)
[17] Energy Policy WA, 2023a. *Review of Supplementary Reserve Capacity Provisions: Stage 2 Information Paper*
[18] *WEM Rules 2023* (WA)
[19] Synergy, 2023a. Synergy - About us
[20] Ernst & Young, 2022a. *The role of distributed energy resources in today's energy grid transition*

In WA, the benefits and challenges of the energy transition are heightened by unique characteristics, including remote location, large, isolated transmission and distribution networks, abundant sunlight, and seasonal weather conditions.

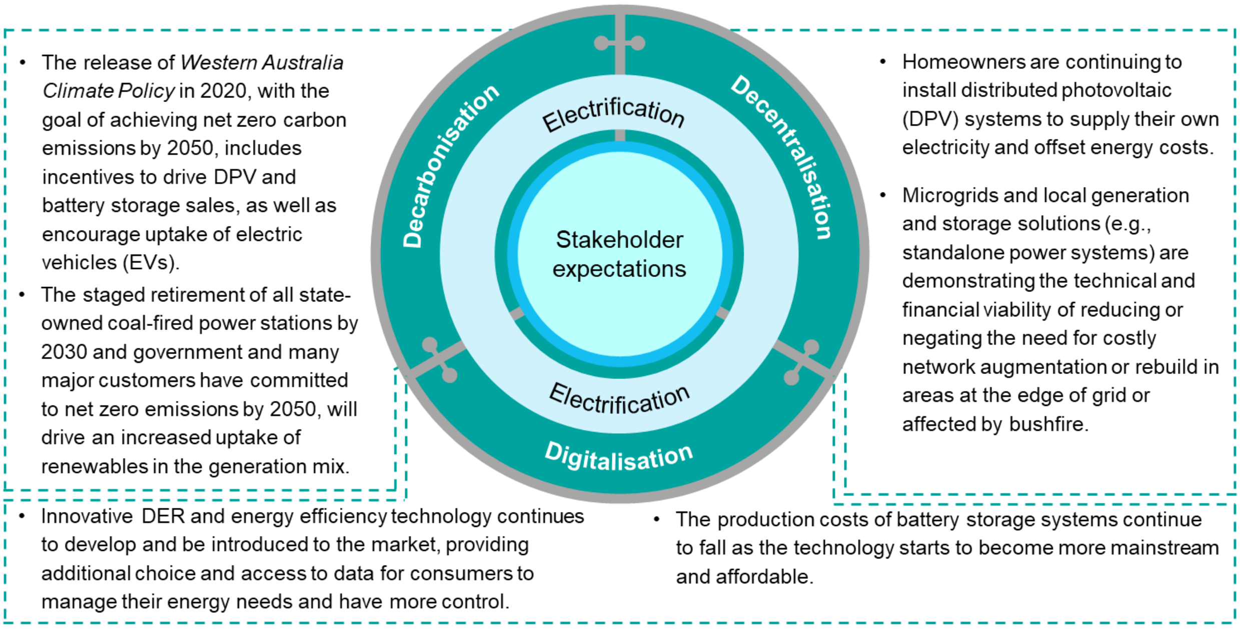

Figure 3: The 3 D's of energy transition impacting WA [21,22]

The total number of DER in WA has increased by 22% from 2020 to 2022.[23] Though DER growth slowed through 2022 due to disruptions from the COVID-19 pandemic and global supply chain constraints, as the economy bounces back from these disruptions, DER growth is expected to continue to accelerate.[24]

A key result of the high penetration of DER is the bi-directional flow of electricity on networks that were designed for one-way flow, as represented in Figure 4:

[21] Adapted from: Ernst & Young, 2022a. p. 11
[22] The WA Government does not offer any financial incentives or rebates for the purchase of distributed energy storage systems (e.g., battery storage)
[23] AEMO, 2023b. [AEMO | DER Data downloads] (accessed 19 October 2023)
[24] AEMO, 2022a

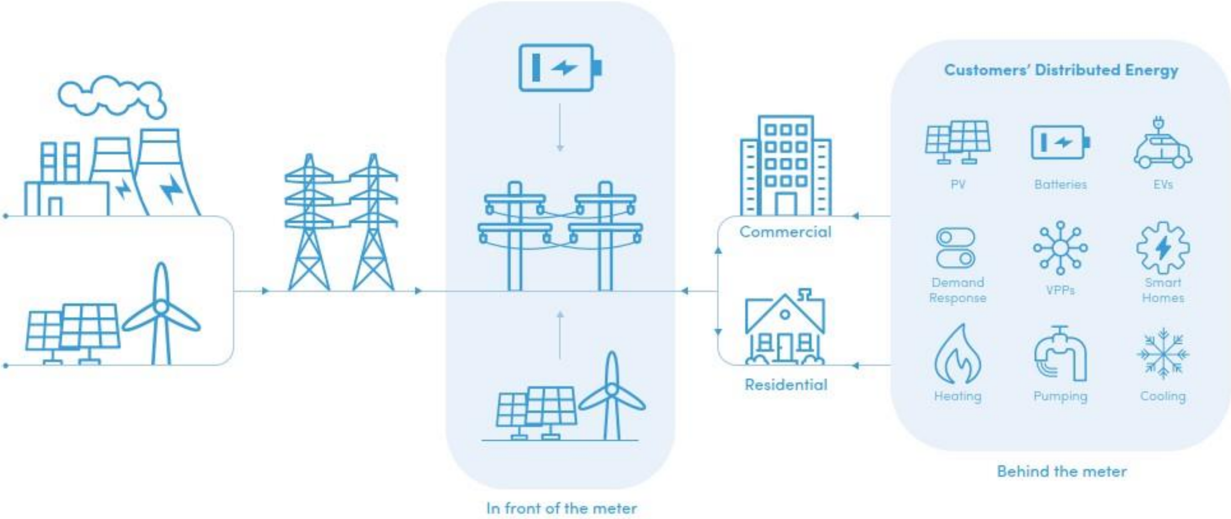

Figure 4: Shift of the energy value chain to bi-directional flow of electricity[25]

The bi-directional flow of energy, with increasing volume of energy exported back to the grid by customers, has the potential to cause various system stability and resilience issues for network and system operators, as well as providers of ESS[26] (the non-energy services that ensure the parameters of the network stay within suitable limits to keep the grid in a stable and reliable state[27]). The high volume of customer DPV capacity is a leading factor in these issues which, if left unmanaged, presents a risk to power system stability during times where demand on the system is low.

To illustrate the disruptive potential of DER, an operational demand minimum of 595MW was recorded on 25 September 2023,[28] which coincided with seasonally mild temperate and sunny weather, where 76.3% of total generation capacity was provided by DPV, as shown in Figure 5.

[25] Energy Transformation Taskforce, 2019a. *Distributed Energy Resources Roadmap*, p. 17
[26] Western Power, Synergy, AEMO, & Energy Policy WA, 2022a. *Project Symphony: DER Service Valuation Report*
[27] AEMC & AEMO, 2022. Essential system services and inertia in the NEM, (aemc.gov.au) (accessed 14 February 2023)
[28] AEMO, 2023c. AEMO | WEM data dashboard (accessed 5 October 2023)

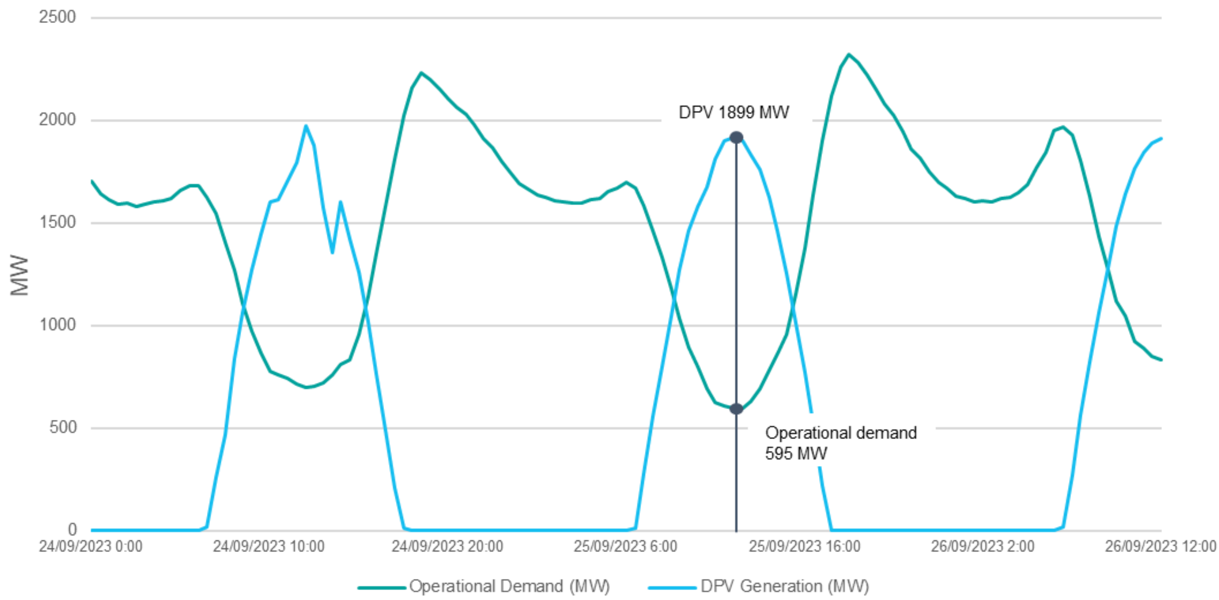

Figure 5: Correlation between operational demand and DPV generation[29]

AEMO has suggested that the operational conditions of the SWIS are likely to become unstable by 2024 unless new mechanisms to counter this risk are implemented.[30]

As an immediate response, the Emergency Solar Management (ESM) mechanism was introduced in February 2022 to address issues arising from the rapid growth of DPV systems in the SWIS. Participation in the ESM is mandatory for DPV systems with an inverter size of 5kW or less that were installed or upgraded after 14 February 2022. Under the ESM, DPV systems are remotely turned down to avoid emergency operating states arising from low load conditions where power system security cannot be ensured.[31] The use of ESM is a last resort emergency backstop measure and whilst there may be negative customer sentiment if used often, the estimated impact to a customer's solar feed-in tariff is estimated to be approximately $1 per curtailment event. In October 2023, Synergy also commenced a Solar Rewards initiative to temporarily turn off participating households' DPV during low demand periods in return for a $100 credit on the customer's electricity bill.[32]

2.3 The DER Roadmap

As a direct result of the challenges and opportunities that DER growth brings, the Energy Transformation Taskforce (the Taskforce) was established by the WA Government in 2019 and operated until 2021 to develop an Energy Transformation Strategy (the Strategy) for the State, provide oversight of the initiatives identified in the Strategy and ensure that the benefits and challenges of DER uptake and large-scale renewable generation are appropriately managed. The Taskforce's vision is:

[29] AEMO, 2023b
[30] AEMO, 2021a. Renewable Energy Integration: SWIS Update (accessed 8 March 2023)
[31] AEMO, 2022a
[32] Synergy, 2023b. Solar Rewards (synergy.net.au)

A future where DER is integral to a safe, reliable and efficient electricity system, and where the full capabilities of DER can provide benefits and value to all customers.[33]

Following the publication of the Strategy, the Taskforce released the DER Roadmap in December 2019, which set out the actions required to improve the integration of DER into the SWIS and the WEM and progress the required policy and regulatory changes.

The DER Roadmap consists of four key themes:

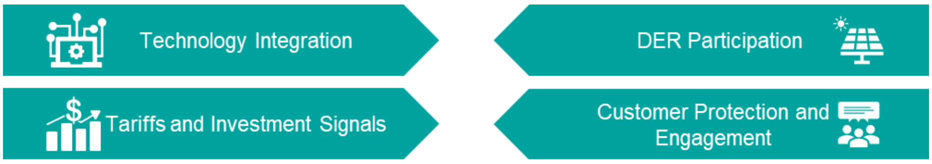

Figure 6: DER Roadmap themes

Under the DER Participation theme, there was recognition of the potential value of carefully managed and orchestrated DER in the SWIS and the multiple opportunities to generate value for customers, the network operator, the market operator and participants, and the broader community. The DER Roadmap recognises that whilst there are several technical and logistical challenges to DER orchestration that will need to be overcome, and an investment in the development of new business capabilities to realise the full potential value of DER[34], the opportunities presented by DER orchestration can fundamentally change how all consumers can access the benefits of energy participation.

DER Roles and Responsibilities

A key element of the DER Roadmap was to develop the initial capability for DER participation, which included establishing an agreed definition of the Distribution System Operator (DSO) and Distribution Market Operator (DMO) in the SWIS and identifying any changes to legislation or regulatory frameworks to support their establishment. An information paper articulating the DER orchestration roles and responsibilities was published by Energy Policy WA in May 2022,[35] which considered the early design and structure of roles and responsibilities that were developed during the initiation of Project Symphony. The discussions regarding DER roles and responsibilities are ongoing and will be informed by the findings of Project Symphony. The roles and responsibilities of each actor in Project Symphony is discussed in further detail in section 3.1.

Implementation of a Virtual Power Plant

The DER Roadmap refers to the establishment of a VPP technology and market participation Pilot to demonstrate the capability and benefits of DER orchestration. The use of a VPP to orchestrate DER involves the aggregation of DER assets: a third party negotiates contracts with DER owners, detailing the services each DER is being contracted to provide, and providing an avenue for DER owners to participate in the electricity market. These third parties develop a portfolio of DER, across multiple owners and locations, and aggregate capacity to buy and sell electricity and electricity-related services in the relevant markets.

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[33] Energy Transformation Taskforce, 2019a. p. 8
[34] Energy Transformation Taskforce, 2019a
[35] Energy Policy WA, 2022. *DER Roadmap: DER Orchestration Roles & Responsibilities Information Paper*

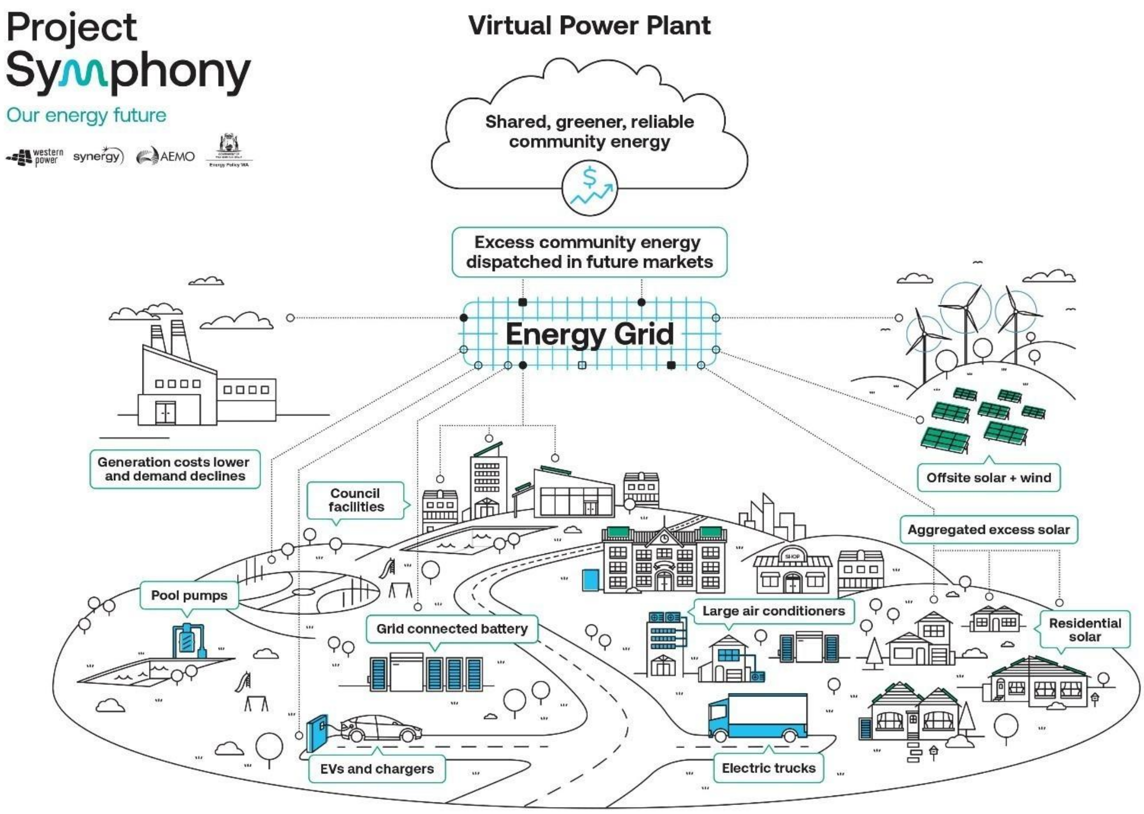

Figure 7: Representation of a VPP structure[36]

In WA, DER orchestration under a VPP would need to be demonstrated as commercially and operationally viable, and any required market reforms implemented, prior to 2024 to help alleviate the system stability issues that AEMO predicts will arise by then. As such, the DER Roadmap sets out the need for a DER orchestration pilot and outlines two related actions.[37]

22 To commence a comprehensive VPP technology pilot, focusing on technical performance of DER.

23 To complete a comprehensive VPP market participation pilot, testing the use of aggregated DER in the WEM and required services

Figure 8: DER Roadmap pilot actions

In response to these two actions, Project Symphony was established. The project is unique relative to other DER trials in Australia as it seeks to pilot a new end-to-end energy market,[38] combining both new and existing assets that meet various criteria depending on the type of DER asset (e.g., rooftop DPV, battery storage, air conditioner, etc.). As such, it builds on the existing knowledge base, incorporating key learnings from a range of independent DER integration trials into “an end-to-end DER services market with new rules

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[36] AEMO, 2022c. [AEMO | Project Symphony] (accessed 8 March 2023)
[37] Energy Transformation Taskforce, 2019a
[38] The only other trial of this nature being Project EDGE in the NEM

for participation."[39] Importantly, the outcomes from Project Symphony will also seek to inform the development and implementation of other actions outlined in the DER Roadmap. Further details on Project Symphony are provided in section 3.

Although the tenure of the Taskforce has concluded, the implementation of the energy transformation strategy, including the DER Roadmap actions and progression of legislative and regulatory reform in the WEM is being continued by Energy Policy WA in partnership with Synergy, Western Power, Horizon Power and AEMO.

2.4 Changes occurring in the Wholesale Electricity Market

The WEM is a dedicated marketplace in the SWIS to buy and sell electricity and relies on mechanisms such as the RCM and a single market clearing price to encourage investment in generation. The original market design of the WEM implemented a day-ahead structure and a single market clearing price with unconstrained access to the network. As such, the market published a single price for each trading interval to be used by all market participants, with no consideration provided to the geographical location of those participants.[40]

In response to the changing energy value chain and actions in the Energy Transformation Strategy, the WA Government has implemented a range of WEM reforms that came into effect in October 2023.

The SWIS, and electricity networks in it, have historically been designed to accommodate the one-way flow of electricity. As such, the WEM Rules were designed in consideration of large generators and loads and were not designed to accommodate the proliferation of DER and intermittent generation such as renewables. To improve the overall system stability and reliability of the SWIS, the amended WEM Rules enables access to the network on a constrained basis with the implementation of a Security-Constrained Economic Dispatch (SCED) structure[41] with five-minute dispatch intervals, increasing the ability to efficiently maintain system security and reliability with the changing energy mix.[42] As part of these reforms, the following changes were implemented:

- The Balancing Market and Load Following Ancillary Service (LFAS) Market was replaced by a new Real-Time Market (RTM) to enable co-optimisation of energy dispatch and frequency control ESS via a new WEM Dispatch Engine.[43]
- The RCM implemented the Network Access Quantities (NAQ) framework and changes to Reserve Capacity Testing and Reserve Capacity Obligation Quantities, in addition to changes implemented in 2021 regarding the registration framework and inclusion of electric storage resources.[44] The cost of resolving system constraints is now offset through energy-uplift payments to market participants, where higher-cost generators are dispatched and through the allocation of NAQs.
- Changes to registration for rule participants and facilities, and the relevant classes, including combining the Market Generator, Market Customer, and Ancillary Service Provider rule participant classes into the one Market Participant class.[45]
- Over 50 WEM procedures either newly developed or significantly changed.[46]

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[39] Energy Transformation Taskforce, 2019a. p. 18
[40] Economic Regulation Authority, 2022a. *Triennial Review of the Effectiveness of the Wholesale Electricity Market 2022*
[41] AEMO, 2021b. *Fact Sheet – WEM Reform Implementation Plan*
[42] AEMO, 2023d. *WEM Reform: Wholesale Electricity Market Design Summary*
[43] AEMO, 2021b
[44] AEMO, 2021b
[45] Energy Policy WA, 2023b. *Consolidated Companion Version of the Wholesale Electricity Market Rules*, c. 2.28.1
[46] AEMO, 2021b

The Short-term Energy Market (STEM) will be retained with a single clearing price. The WEM reforms also result in ancillary services being replaced by ESS. These services have been categorised into either Frequency Co-Optimised ESS (FCESS) or Non-Co-optimised ESS (NCESS).

FCESS is co-optimised with energy dispatch in the RTM and includes the following five services:

- Contingency Reserve Raise.
- Contingency Reserve Lower.
- Regulation Raise.
- Regulation Lower.
- Rate of Change of Frequency (RoCoF) Control Services.

Provision of these services are monitored to ensure barriers to entry remain low, increasing competition and assisting in keeping prices low for customers.[47]

NCESS are services that do not relate to frequency control and generally emerge during the system planning processes. The need for NCESS may be triggered to avoid or defer network augmentation that has been identified in Western Power's 10-year transmission plan, to respond to a change in the power system which may threaten system security, or to meet a new or modified power system security standard. The Framework for NCESS[48] provides the following examples of NCESS: active power, reactive power, voltage support, fault level, and network support in regions where reliability cannot meet expectation.

Energy and Governance Legislation Reform

In addition to the WEM reforms, further reform considers changes to the governance of WA's energy sector. A range of enabling amendments to the *Electricity Industry Act 2004* (EI Act) are being progressed by Energy Policy WA through the *Electricity Industry Amendment (Distributed Energy Resources) Bill 2023* (Amendment Bill)[49] that follow on from the changes that have already been implemented as part of the Energy Transformation Strategy. Draft amendments in the Amendment Bill were published for public comment, which include the introduction of a State Electricity Objective (SEO) in the EI Act to replace the WEM objectives and expand the scope of the WEM Rules, as well as further changes to the Electricity System and Market Rules (ESMR).[50]

Further information on the WEM, the Energy Transformation Strategy, DER participation, and energy market reforms can be found via Energy Policy WA's website.[51]

[47] Energy Transformation Taskforce, 2020a. *Supplementary ESS Procurement Mechanism*
[48] Energy Transformation Taskforce, 2021
[49] Energy Policy WA, 2023c. Project Eagle Energy and Governance Legislation Reform (www.wa.gov.au)
[50] Energy Policy WA, 2023d. *Electricity Industry Amendment (DER) Bill – Consultation paper*
[51] Energy Policy WA, 2023c

3. Project Symphony

Project Symphony is a collaborative pilot project between Western Power, Synergy, AEMO and Energy Policy WA (EPWA), with funding support from ARENA. It is designed to test the technical viability and commercial value and viability of DER orchestration for a range of stakeholders and DER assets and inform the future development of energy policies and regulations. The Pilot is one of the cornerstones of the DER Roadmap, supporting its vision:

To progress toward a future where the integration and participation of DER in markets supports a safe, reliable, lower carbon and more efficient electricity system.[52]

To deliver on this vision, as well as actions from the DER Roadmap, Project Symphony tested a version of the "Hybrid model" developed in the Open Energy Networks (OpEN) project.[53] This approach evolves the current responsibilities of the existing network operator (Western Power), existing retailer (Synergy) and the power system and market operator (AEMO) to deliver the required functions to enable DER orchestration in the SWIS, shown in Figure 9.

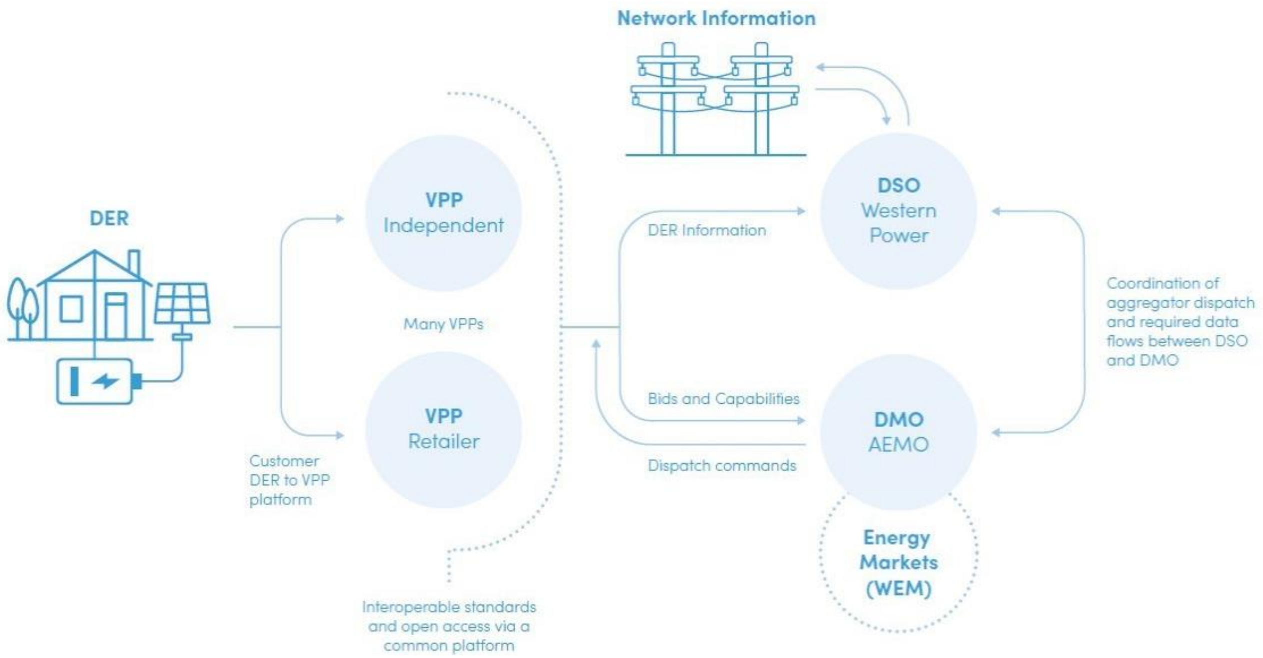

Figure 9: A possible DSO/DMO model for WA[54]

The hybrid model includes a two-sided market platform for trading both wholesale electricity and FCESS that is operated by the DMO. Market participants can use this platform to submit bids and offers for system services, enabling the DMO to co-optimise dispatch of electricity and FCESS across the transmission and distribution networks. DER is included in the optimised dispatch instructions via the use of a VPP created by an aggregator. The aggregator combines various DER to offer the combined output as services to the market, providing customers with an avenue for participation in the market. The DSO maintains visibility of

[52] Alexander & Blaver, 2021. p. 3
[53] Energy Networks Australia, 2020. *Open Energy Networks Project: Energy Networks Australia Position Paper*
[54] Energy Transformation Taskforce, 2019a

the distribution and transmission networks and provides dynamic operating envelopes (DOEs) to aggregators in response to network constraints, including the impact of DER on the network to accommodate DER dispatch and ensure overall optimisation.

The approach used in the Pilot to publish and assign DOEs dictated that for customers to be assigned a DOE, they must have a contractual relationship with an aggregator (Synergy) or a TPA to receive the DOE. Under this construct, DER customers who elect not to participate in a VPP cannot receive a DOE.

Further explanation of the roles included in the version of the hybrid model implemented in Project Symphony is detailed below.

3.1 DER Orchestration Roles

The roles and responsibilities outlined in the OpEN hybrid model represent a significant evolution of the roles that currently exist in the WEM, with the model centred around the new DSO and DMO roles and their ability to communicate effectively with each other and the other parties involved. As such, the implementation of these roles would require changes to the current regulatory and legislative frameworks, the identification of which falls under Action 25 of the DER Roadmap. By piloting these roles, Project Symphony assists in informing these regulatory and legislative changes, with the fulfilment of these roles in the Pilot in line with policy positions set out in the *DER Roles and Responsibilities Information Paper*.[55]

The Project Symphony partners were required to fulfill three key roles as part of the Pilot.

Figure 10: DER orchestration roles

The roles of TPAs were also piloted to consider an alternative method to recruit customers and their DER into the VPP tested by Project Symphony, allowing TPAs to enter the market via contracts with Synergy.

Distribution Market Operator

The DMO role is independent of any WEM participants and an expansion of AEMO's existing role of the market operator and system operator overseeing the WEM and progressive integration of small-scale generators, such as DER, to be orchestrated and dispatched at appropriate scale. As part of managing the market and power system, the DMO also oversees the different elements, including electricity dispatch, ESS, and reserve capacity. They must be able to manage aggregation of DER and larger generators simultaneously, providing security and stability for the entire system and co-optimised dispatch. With the rapid growth of DER, the DMO is also responsible for providing access to the electricity, capacity, and ESS markets for aggregators.[56]

As previously discussed, it is imperative that the DMO can seamlessly integrate with the DSO to co-optimise dispatch of electricity with FCESS whilst integrating NCESS requirements. As the DMO, AEMO was responsible for the development of a market platform to provide aggregators access to the wholesale

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[55] Energy Transformation Taskforce, 2020b. *Issues Paper – DER Roadmap: Distributed Energy Resources Orchestration Roles and Responsibilities*
[56] Energy Transformation Taskforce, 2020b

markets. Detail of the AEMO Platform can be found in Project Symphony's *Combined Platform (as built) Report for DSO, DMO and Aggregator report*.

Aggregators

The small capacity size of individual DER assets, when combined with the complexity and requirements of registering as a facility in the WEM, means it is unlikely there will be any material benefit in customers participating directly in the market. However, by aggregating DER into a larger facility, customers are provided with greater potential for value. As such, aggregators are responsible for consolidating multiple DER into a single facility that can then participate in the wholesale and retail electricity markets or provide services to the DSO. As an aggregator oversees multiple DER, each DER asset is required to be capable of communicating with the relevant aggregator. As part of their role, aggregators will need to develop their own DER portfolios that can provide services that may include, but not limited to:

- Electricity bids and offers
- ESS
- Demand-side management
- Network support
- Minimum Demand Service
- Supplementary Reserve Capacity.

Aggregators are also required to provide customers with appropriate compensation for the use of their DER, reflective of the market value for providing those services.[57]

As mentioned, Synergy is the only retailer in the WEM for non-contestable customers such as residential customers. As such, Synergy took on a Parent Aggregator role in the Pilot and was responsible for DER valuation, acquiring customers and procuring a minimum of two additional TPAs for the Pilot. Additionally, Synergy was responsible for developing an Aggregator Platform to orchestrate DER assets, allowing DER to participate in the wholesale markets. This included ensuring the platform was able to facilitate communication between aggregators and the DSO and AEMO, ensuring market submissions adhered to DOEs published by Western Power as the DSO and dispatch of DER complied with dispatch instructions sent by AEMO as the DMO.[58] The Aggregator Platform also needed to allow TPAs to interface with the platform to access the wholesale market via the parent aggregator and broader value chain. During the Pilot, Synergy was responsible for onboarding these third parties, allowing them to test new business models whilst using the Aggregator Platform Synergy developed.[59] Detail of the Aggregator Platform can be found in Project Symphony's *Combined Platform (as built) Report for DSO, DMO and Aggregator report*.

Distribution System Operator

The role of the DSO is to provide access to the network, manage the system by developing it to integrate with the various types of generators (including DER), and manage demand. The DSO needs to ensure the network remains within technical limits and identify and address issues in a timely manner. This includes engaging with NSS providers. In providing instructions to DER aggregators to address issues, the DSO is responsible for communicating with the DMO to support oversight of operations and the overall market. The

[57] Energy Transformation Taskforce, 2020b
[58] Western Power, Synergy, AEMO, & Energy Policy WA, 2022b. *Project Symphony: Platform Functional and Non-Functional Requirements*
[59] Western Power *et al.*, 2022a

DSO is also responsible for creating DOEs to communicate constraints on the network to other market participants.[60]

Given that Western Power is the only network operator in the SWIS, it assumed the role of DSO. Like the DMO, to ensure efficient and effective communication between the DSO, DMO and aggregators, a DSO Platform needed to be developed. The platform was developed by Western Power as the DSO and required capabilities to:

- Forecast passive energy
- Identify network constraints in the system
- Determine the available hosting capacity of the distribution network
- Allocate spare capacity using an allocation method to calculate the DOEs
- Increase visibility of the network to validate compliance with DOEs and NSS

Details of the DSO Platform can be found in Project Symphony's *Combined Platform (as built) Report for DSO, DMO and Aggregator report*.

3.2 Pilot Objectives

The overarching objective of the Pilot was to determine the degree to which improved integration of DER with the network can address the opportunities and challenges presented by the growth of DER. This included the use of DER for constraint management whilst also assessing DER orchestration viability, with consideration to its impact on the network's stability and reliability, and whether it was a cost-effective solution.[61]

In parallel to the overarching objective, the Pilot also sought to trial a new electricity market model, to test the technical capability of a VPP across four discrete test scenarios and determine the viability of a market participation model focused on customer DER aggregation. As part of this, the Pilot sought to test the roles and responsibilities outlined in the OpEN Hybrid model as discussed above and determine whether this was the optimal model to maximise value. This included identifying the value proposition available to customers, value drivers, and the overall value stack across the various Pilot participants.[62]

Lastly, the Pilot sought to gather insights and data to form the basis on which policy and regulatory reform decisions are made, providing an evidence base for future investments. This includes the development of relevant standards, processes, planning and other frameworks to ensure system security and reliability, and optimised DER integration into the network.[63]

3.3 Pilot Test Scenarios

Project Symphony identified four key market, non-market, system and network scenarios (test scenarios) to be tested in the Pilot.

Bi-Directional Energy – Balancing Market

Network Support Services

[60] Energy Transformation Taskforce, 2020b
[61] Alexander & Blaver, 2021
[62] Alexander & Blaver, 2021
[63] Alexander & Blaver, 2021

Constrain to Zero

Essential System Service – Contingency Reserve Raise

Figure 11: Project Symphony test scenarios

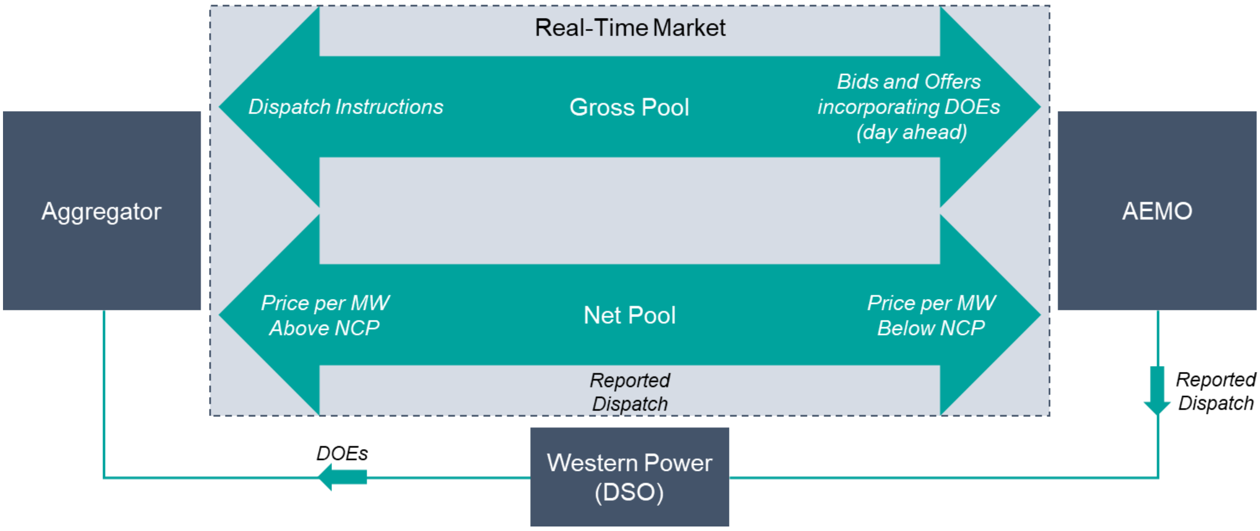
As a Pilot, testing of the four test scenarios was carried out in a simulated environment based on bi-directional energy, with triggers for the respective services (NSS, Constrain to Zero, and Contingency Reserve Raise) simulated to test the capabilities of Project Symphony's solution in managing each of them. A base case "Do nothing" scenario was also developed to provide a reference point against which to measure the increase (or decrease) of value generated in each of the test scenarios.

Bi-directional Energy – Balancing Market

The Balancing Market was replaced by the RTM in October 2023 and comprises of a 'gross pool' market for the dispatch of energy and FCESS and a 'net pool' for settlement that enables the most economically efficient dispatch of generation to meet system electricity demand at any given time.[64]

Although most energy is traded between market participants via bilateral contracts that sit outside of the market administered by AEMO, the balancing market in the RTM enables market participants to adjust their net contracted position (NCP) to take into account changes that occur in the market in real time, such as a change in demand compared to forecast, unplanned outages or network constraints.

The difference between the actual energy supplied or consumed and NCP quantities are settled using the market clearing prices determined in the RTM.[65] By using a gross pool to determine dispatch and a net pool to incorporate the difference into settlement, the RTM can calculate optimal electricity generation to satisfy demand on a continuous basis. All facilities that are registered with AEMO, including VPPs, are required to participate in the gross pool and adhere to the dispatch instructions sent by AEMO. It includes access to the wholesale market, allowing aggregators to sell or buy electricity in the RTM whilst incorporating or adhering to a DOE provided by the DSO (Western Power) to the Aggregator, maximising renewable hosting capacity on the network.[66] This is depicted in Figure 12, which shows a high-level overview of the RTM.



[64] Alexander & Blaver, 2021. p. 39
[65] AEMO, 2023d
[66] Western Power *et al.*, 2022b

Figure 12: Bi-directional flow of the Real-Time Market

Project Symphony sought to test the ability of orchestrated DER to participate in the RTM's gross pool for wholesale energy trading through a simulated market platform. Though the net pool is included in the design of the RTM, the Pilot did not test orchestrating DER to participate in the STEM, resulting in a pure gross pool mechanism. Additionally, though the RTM includes co-optimisation of FCESS, Project Symphony's Pilot built a framework to test DER orchestrated via a VPP to provide both energy and ESS. The Pilot included testing of one FCESS (Contingency Reserve Raise), this was treated as its own test scenario market clearing of RTM submission of both Energy and Contingency Reserve Raise. In testing orchestrated DER's capabilities to trade in wholesale energy markets, the Pilot hoped to demonstrate the use of the DSO Platform to determine the equal distribution of available capacity. In Project Symphony, the DSO published DOEs, which the aggregator used to inform their facility capacity and factored into their RTM bid and offer for both Energy and Contingency Reserve Raise. The AEMO Platform then incorporated the bids and offers received into the dispatch instructions sent to the Aggregator via the RTM. Seamless integration would allow the Aggregator Platform to automatically constrain customer DER assets in its area to adhere to the DOE, either increasing or decreasing import or export of electricity in the network. As such, through managing import and export of electricity, it utilises bi-directional energy to balance the market on a continuous basis.

Additionally, market prices used to value wholesale energy trade in the CBA modelling were based on historical prices reported for the balancing market that was part of the old WEM constructs. As such, the balancing price for each trading interval was a simulated price and not necessarily reflective of market prices under the new WEM that went live in October 2023.

Network Support Services

NSS are a contracted service provided by a third party to the network operator/DSO (Western Power) to help manage or solve localised network constraints. NSS can alleviate distribution level peak electricity demand or reverse power flow and/or local voltage issues identified by Western Power and provides an alternate non-network solution to defer the cost of network augmentation, which can be delivered at a lower cost than traditional network augmentation such as the installation of new transformers, zone substations or feeders.

NSS are planned to be included under the NCESS framework introduced in January 2022 and refers to services to manage localised network constraints. Though it is expected that the use of DOEs will minimise the need for NSS, as they aim to maximise the renewable energy hosting capacity whilst maintaining safe network operating limits, they will not remove the need for NSS entirely, and in particularly where it can be demonstrated that NSS can deliver the most cost-efficient solution for the market and consumers. This is due to distribution networks being designed in consideration of After Diversity Maximum Demand (ADMD), which is the total maximum import capacity for each customer connected to a specific upstream network location after taking diversity of demand into account, averaged over the number of customers. As it is highly irregular to have large numbers of connection points consuming electricity at maximum capacity simultaneously, the ADMD is usually less than the import capacity limits of individual connection points, making it possible for import/export to be higher than the ADMD, particularly during seasonal periods of peak demand or if the distribution network has changed since its original design, such as the connection of new DER.[67] NSS would be used to manage these situations, increasing either export or import or decreasing imports of DER assets connected to the specified location, as represented in Figure 13 and Figure 14 below.

[67] Western Power *et al.*, 2022b

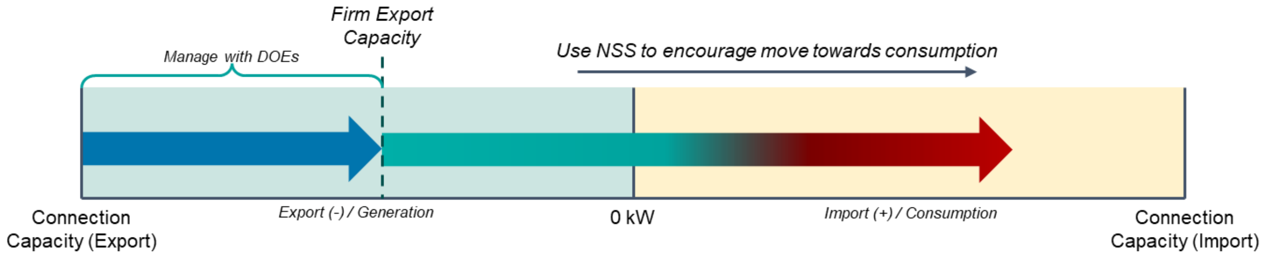


Figure 13: NSS impact on service connection – reduce export[68]

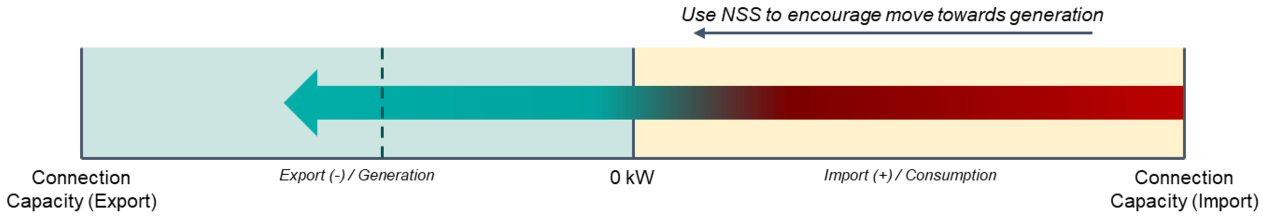


Figure 14: NSS impact on service connection – reduce import[69]

Previously, safe operating limits have been maintained primarily through augmentation of the local distribution networks, requiring significant investment to manage an issue that is only relevant for a few of hours each year. By using contracted NSS provided by a relevant market participant (i.e., the market participant has a facility registered to provide NSS), it is expected that augmentation will be deferred, reduced, or even avoided. As mentioned, in the new WEM Rules, aggregators will be included under the market participant class making them a potential provider of NSS via the use of customer DER assets in their portfolio.

Project Symphony sought to demonstrate the use of available DER orchestration to alleviate local network constraints. This included using the DSO Platform to analyse data, model and forecast the behaviour of the network, and identify NSS requirements throughout the distribution network. As such, the Pilot required Western Power to maintain visibility of Medium Voltage (MV) and Low Voltage (LV) networks within the Pilot area, the scope of which is shown in Figure 15.

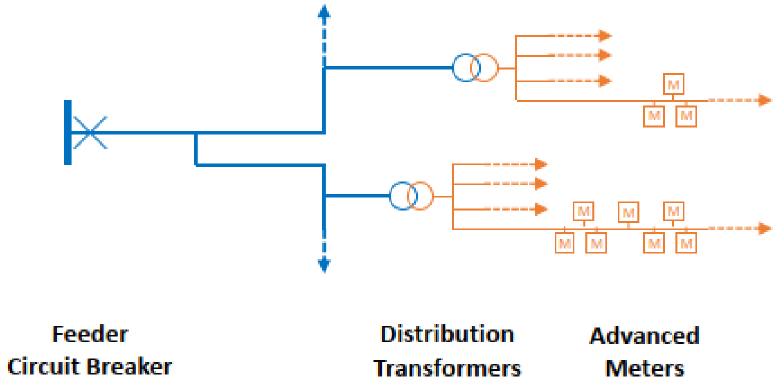


Figure 15: Scope of Project Symphony network monitoring[70]

This monitoring data would allow the DSO Platform to identify NSS requirements on the network, signalling to the AEMO Platform that NSS is required at a particular location and to send dispatch instructions to the

[68] Western Power *et al.*, 2022b. p. 31
[69] Western Power *et al.*, 2022b. p. 30
[70] Western Power *et al.*, 2022b. p. 32

Aggregator Platform to provide the relevant NSS. The Aggregator Platform would then use the specified DER assets in that location to either generate or absorb electricity to control local voltage or manage the load on interconnectors via changes to generation or load shedding.[71]

Constrain to Zero

Constrain to Zero is a conceptual NCESS that will be managed by AEMO and is not defined in any regulatory instruments, including the new WEM Rules. The service is a pre-emergency service provided by a VPP to AEMO, demonstrating the AEMO Platform's ability to instruct the Aggregator Platform to constrain energy output from DER to zero export (net) or zero output (gross) at times of low load. In constraining export to net zero, the limit is set at the metering connection point, either limiting the DER asset to zero export or instructing it to import to the point where the overall export of electricity across the network becomes zero,[72] as displayed below:

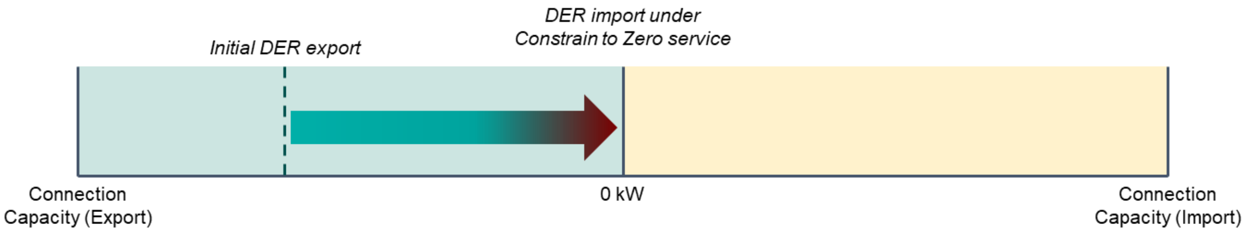


Figure 16: DER constrained to net zero at the metering connection point

Where constraining to net zero keeps DER assets online, constraining export to gross zero refers to switching DER assets off so to achieve zero generation, resulting in energy being imported from the grid.[73] This is depicted in Figure 17.

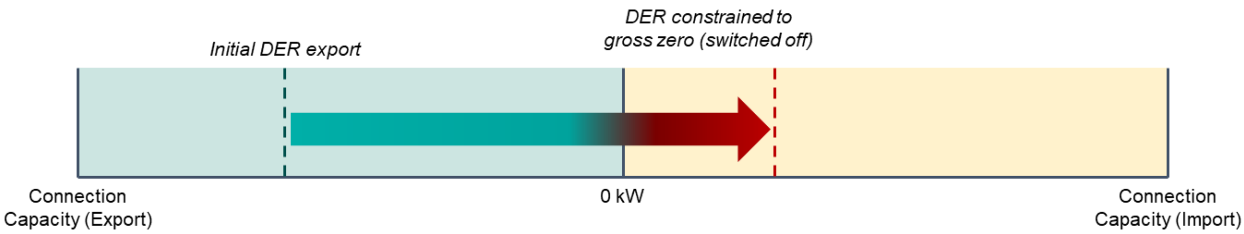


Figure 17: DER constrained to gross zero

It is important to note that the Constrain to Zero service is an opt-in service for VPP participants and distinct from the mandatory ESM mechanism introduced in the SWIS in February 2022.

As part of the Pilot, Project Symphony sought to demonstrate the use of the AEMO Platform to identify when a minimum demand event is likely to occur due to low system load and implementing the Constrain to Zero net or gross service to mitigate the risk. To do this, the AEMO Platform sends a signal to the Aggregator Platform, which could then constrain export of individual DER to raise net import across the network. As it is not a service currently considered by regulations, the Pilot sought to use insights gathered from this test scenario to provide recommendations on future regulatory guidelines. However, it did not establish a price for this service in the absence of an existing market.

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[71] Western Power *et al.*, 2022b
[72] Western Power *et al.*, 2022b
[73] Western Power *et al.*, 2022b

Essential System Service – Contingency Reserve Raise

Contingency Reserve Raise (ESS-CRR) is a market-provided response to a locally detected drop in frequency which involves rapidly raising frequency, so it returns to within the normal operating band, 50Hz ± 0.2 when a 'contingency event' occurs, such as the sudden loss of a large generator or unexpected surge in load.

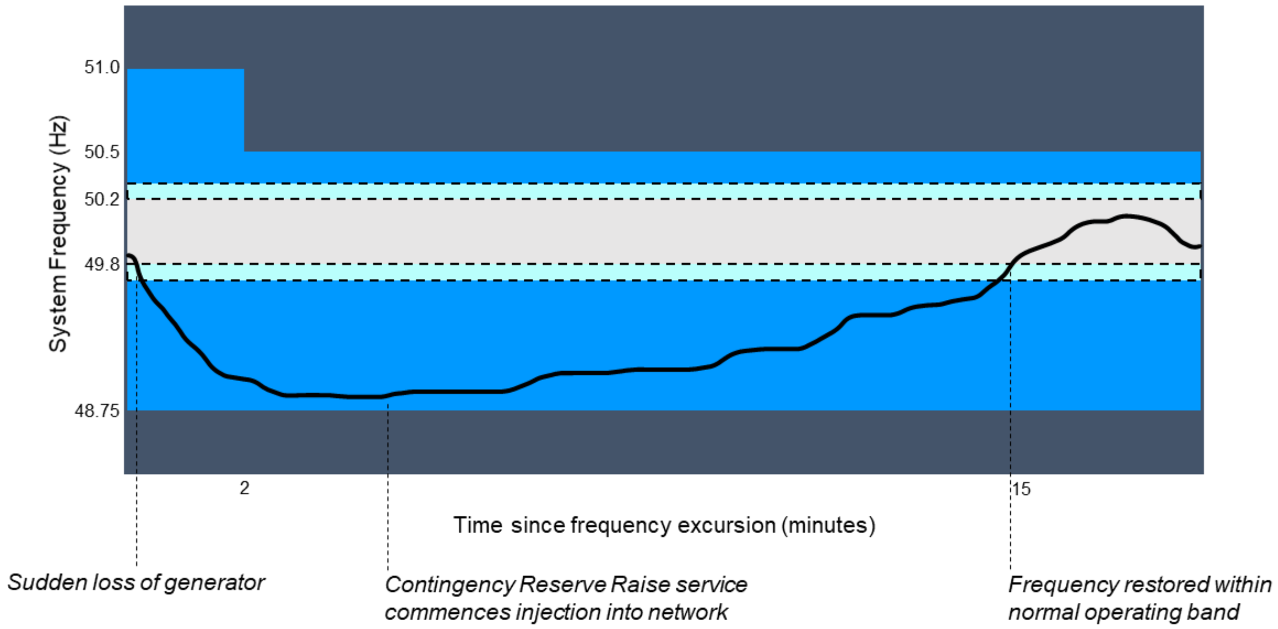

Figure 18: Restoration of frequency using Contingency Reserve Raise service[74]

The Pilot sought to demonstrate the AEMO Platform's capability to identify the occurrence of a contingency event and address it as required using DER. The platform would detect a low frequency and send a signal to the Aggregator Platform, instructing it to rapidly increase the electricity fed into the system from an identified DER asset to raise the frequency in the system. Testing of ESS-CRR in Project Symphony can be characterised into two categories.

- **Simulated ESS-CRR test -** the Aggregator offered their capacity and a price for ESS-CR to the market to be enabled. Scheduled tests based off historical contingency events in the SWIS were tested across the VPP fleet during the pilot. This consisted of simulating a real ESS-CR event based on pre-recorded droop responses to historic frequency contingencies in the WEM, which were scheduled at the droplet level by the droplet supplier. The DMO would send pre-determined ESS enablement and ESS test instructions through pre-dispatch and dispatch instructions to the Aggregator. The Aggregator then responded to the simulated frequency event at the scheduled time.
- **Responding to a credible system event –** Again, the Aggregator offered their capacity and a price for ESS-CR to the market. If successful, the Aggregator enabled the facility to respond to a real contingency raise frequency event via the inverter droop response. If a credible frequency event occurs, the facility responds to a frequency decrease (<49.975Hz) by injecting energy proportional to the frequency deviation. Frequency is monitored at and responded to at the device level.

Like the Bi-directional Balancing Market test scenario, there was no actual reported pricing for the ESS-CRR service due to it being a new service introduced in October 2023. Thus, the pilot built a simulated value for a trading interval for ESS CRR based on the Margin values methodology in alignment with the Balancing price used for energy. The price for ESS-CRR in the CBA modelling was determined using historical margins for

[74] Adapted from: AEMO, 2023d. p. 46

the Spinning Reserve Ancillary Service, which was replaced by ESS-CRR, reported under the old WEM. As such, the ESS-CRR price used is not necessarily reflective of market pricing under the new WEM.

Base case scenario

A base case scenario was developed to provide a counterfactual assessment of each test scenario against an unorchestrated DER scenario, where DER may be managed under the ESM mechanism, but not 'orchestrated'. The base case test scenario takes into consideration the WEM reforms implemented in October 2023, in recognition of these reforms being implemented regardless of the outcome of Project Symphony. As such, under the base case test scenario, the role of the third-party aggregator in a VPP does not exist, nor is customer DER enabled to participate in the WEM and are not used to provide market services, NSS, or a Constrain to Zero service. However, the impact of other scheduled changes in the network, such as the closure of the Synergy's Muja and Collie power stations, and the potential network and generation investment required as a result of decarbonisation initiatives, will be required in the absence of DER orchestration.

3.4 Platform Architecture

As mentioned, the Project required the development of three platforms that have seamless integration capabilities to ensure effective and efficient communication. Through integration of these platforms, end-to-end data flow is established, moving "from customer to off-market settlement via (AEMO),"[75] as shown in Figure 19.

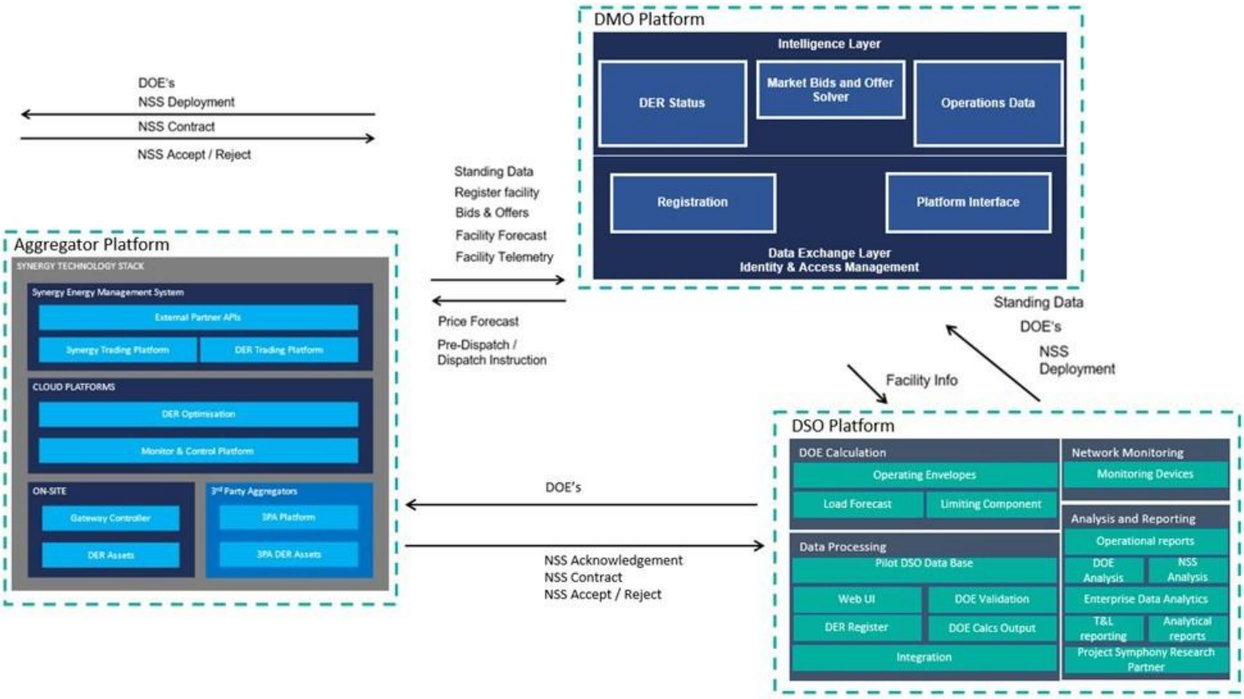

Figure 19: Conceptual platform design and function[76]

An objective of developing the platforms was to establish foundational capability that could be scaled to the mainstream market through the on-market AEMO Platform. However, the development of these platforms

[75] Western Power *et al.*, 2022b. p. 10
[76] Western Power, Synergy, AEMO, & Energy Policy WA, 2023, *Project Symphony: Combined Platform (as built) Report for DSO, DMO and Aggregator*. p. 21

provides a framework for the scaling of the Pilot only; the platforms themselves were originally developed with the aim of delivering the Pilot rather than being a scaled DER orchestration solution, though some project partners report plans to enable the use of their respective platforms for purposes outside of Project Symphony. As such, the development of the platforms for the Pilot focused on delivering the four test scenarios previously mentioned.

A detailed description of each platform is available in the *Combined Platform (as built) Report for DSO, DMO and Aggregator*.[77]

Platform Data Sharing and Platform-to-Platform Integrations

Figure 20 provides an overview of the data sharing requirements between the platforms:

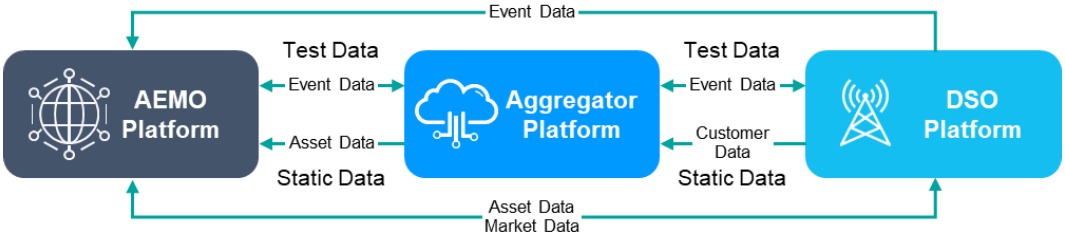

Figure 20: Static and test data sharing between platforms

The static data is standing data that was required to ensure the Pilot could commence testing each test scenario. The test data is the operational data collected during execution of testing and includes event, trigger and outcome data. A key component of the data sharing requirements is the integration requirements, with the source and target of the data being an input/validation of the integration. As part of establishing data sharing integrations between the platforms, a Communications Protocol was developed, covering required data security and privacy requirements. Figure 21 provides an overview of the platform-to-platform integrations developed to enable end-to-end transactions.

[77] Western Power *et al.*, 2023

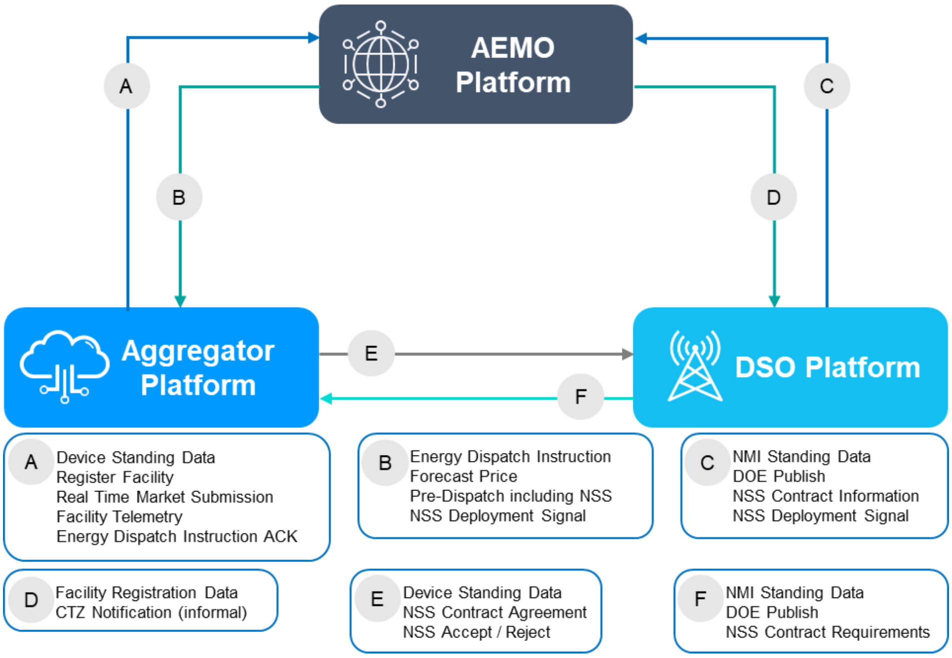

Figure 21: Platform-to-platform integrations[78]

Each of the data classifications shown above are integrated using one of the methodologies outlined below:

Integration Methodology	Type(s)	Description
Automated	API-API (Pull or Push)	Automated data transfer via API format schema
User Interface (UI)	API-API File Drop	Manual data transfer with API format schema via Platform UI

Table 1: Platform integration methodology[79]

Further information on the platforms developed, including the data sharing and hosting arrangements, data classifications, and platform integration methodologies, can be found in the *Project Symphony: DSO, DMO and Aggregator Platforms (as built) Report* knowledge-sharing deliverable.

3.5 Test Plans and Summary of Test Outcomes

To demonstrate the capabilities of orchestrating DER under a VPP across the four test scenarios, Project Symphony utilised a phased approach, testing a range of test cases at various stages. The main phase was the 90-day stability period, which targeted the testing of a mix of DER assets as outlined below.

[78] AEMO, 2022e. *Project Symphony: API Specification Report*, p. 22
[79] AEMO, 2022e. p. 20

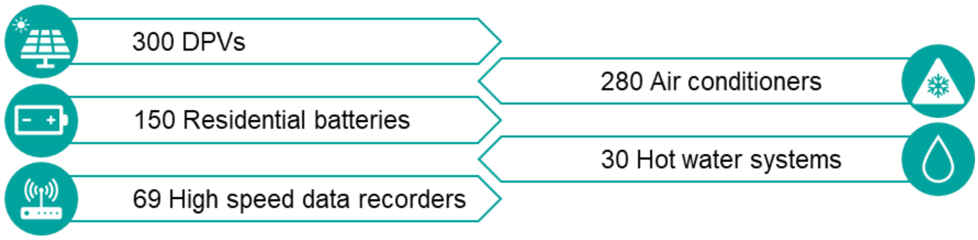

Figure 22: Minimum number of assets required for testing

Additionally, to commence the 90-day stability period, all verification testing needed to be complete with no severity one or two defects remaining open. The project partners also required agreed methods of capturing metrics pertaining to platform availability and asset reliability, ensuring analysis of the stability period is consistent and comparable across all organisations.[80]

To consider the 90-day stability period complete:

- All must-have hypotheses must have been tested with the project partners confirming that the acceptance criteria for data collection and reporting had been satisfied.
- There could be no severity one or two defects open, unless otherwise agreed by the project partners, no more than ten severity three defects, and no more than 20 severity four defects. Each of these defects must also be agreed and accepted by all organisations and added to a log for future design consideration.
- A clear outcome needed to be reached, either positive or negative, regarding Project Symphony's solution and its ability to support the individual test scenarios and combined value stacking hypotheses.[81]

Network testing and verification testing were carried out in March 2023, and the 90-day stability period commenced in April. The test cases also followed a phased approach, as outlined in Figure 23.

Execution Phase	1. Test Readiness Assessment	2. Test	3. Post Test Assessment	5. Analysis and Reporting
Description	Planning and preparation to conduct test and pre-execution	Execution and daily review of tests, including gross analysis	Review of test performance, including test summary report, and data acquired	Drafting of learnings and potential recommendations
Duration	1 Day	6 Days	1 Day	7 Days*
		4. Data Verification		
		Analysis of the data acquired, including provision of partner reports		
		1 Day – ongoing from start of Test Execution		

*Some data analysis will require more than 1 test cycle to meet overall hypothesis/objectives

Figure 23: Execution phases for test cases in Project Symphony[82]

[80] Western Power, Synergy, & AEMO, 2022a. Test & Learn – 90-Day Stability Period Plan
[81] Western Power, Synergy, & AEMO, 2022a
[82] Western Power, Synergy, & AEMO, 2023a. *Project Symphony: Test & Learn Approach*

Table 2 lists the stability period test cases and shows the test scenarios they relate to the Bi-Directional Energy – Balancing Market (BMO); Network Support Services (NSS); Constrain to Zero (CTZ); and Essential System Service – Contingency Reserve Raise (ESS-CRR).

Test Case ID	Test Case Title	Test Scenarios			
		BMO	NSS	CTZ	ESS-CRR
TS18.1	BMO Stable Facility with Constrained Network DOEs: Residential assets under direct Aggregator control	✓			
TS18.2	BMO Stable Facility with Unconstrained and Constrained DOE: Addition of TPA	✓			
TS19.1 – 19.2	BMO and ESS: Stable Facility with Unconstrained and Constrained DOE	✓			✓
TS20.1	Full value stacking (BMO, ESS-CR & NSS) Facility with residential assets under direct Aggregator control: Stable Facility with Constrained DOE	✓	✓		✓
TS20.2 – 20.4	Full value stacking Facility with addition of TPA capability: Stable Facility with Constrained DOE	✓	✓		✓
TS20.5 – 20.7	Full value stacking Facility with DESS and TPA: Stable Facility with Constrained DOE AEMO will use its levers to change price files on the fly and dispatch instructions in a mix that will force the Aggregator to adapt and need to reflect its capability in the market at a close-to-5-minute frequency.	✓	✓		✓
TS21.1 – 21.2	CTZ scenario test TS21.2 was additional testing performed at EPWA's request, repeating TS21.1.			✓	
TS22.1	CTZ scenario test with inclusion of DESS, short notice DOE, Synergy failure to publish DOE to gateways, and NSS dispatch at midday with network constraints	✓	✓	✓	

Table 2: Project Symphony test cases mapped to the relevant test scenarios[83]

Five high-level hypotheses were developed as part of Project Symphony and tested in the test cases listed in Table 2.[84]

[83] Western Power, Synergy, & AEMO, 2022b. *T&L Stability Test Cases – T&L Restart*
[84] Western Power, Synergy, & AEMO, 2022b

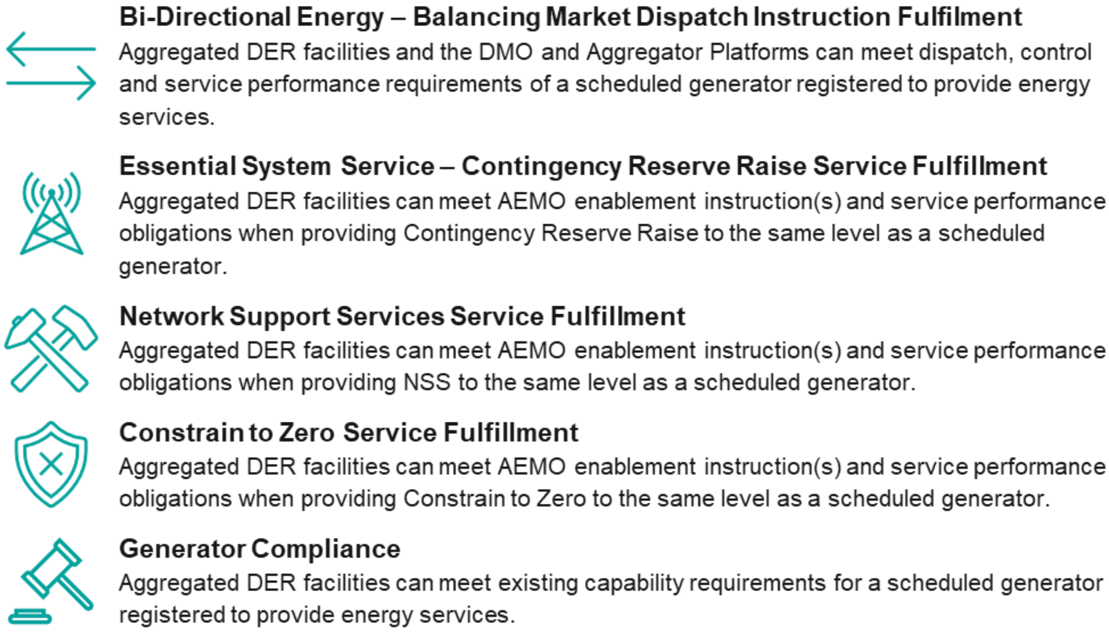

Figure 24: Test case hypotheses

These provided the overarching objectives of the test cases, ensuring the test cases focused on testing the required capabilities of Project Symphony's solution. An additional 95 hypotheses were also developed by Western Power and Synergy, which focused on the specific functionality these project partners required as part of their respective roles.

An overview of the test cases, the objectives of the project partners for each test case, and acceptance criteria for test case execution and data quality and analysis required by each partner, as well as a timeline of the testing of Project Symphony, is provided in the Appendices. Further detail, including information on the hypotheses of each organisation, the test cases, the objectives of each organisation under each test case, and their respective acceptance criteria for execution, data quality, and data analysis, can be found in Western Power's, Synergy's and AEMO's joint test and learn (*T&L) Stability Test Cases – T&L Restart* document.

3.5.1 Summary of Pilot test outcomes

Project Symphony included the execution of a range of test cases aligned to the test scenarios. Summaries of the results of these test cases, including test cases added during testing of the Pilot, are provided below.

TS18.1 BMO with Constrained DOE

A key challenge arising from the Pilot relates to the use of price signals to determine how customer DER should be constrained. It was found that, when energy prices were moderately positive, customer DPV were being constrained under the Constrain to Zero service. This resulted in customers unable to consume energy generated by their own DPV systems (e.g., curtailing gross solar output) and needing to import electricity from the grid instead, increasing customer electricity costs. As such, there was an increase in customer complaints regarding management of their assets. In response, the Project Symphony team developed the improved facility control enhancement, with initial testing occurring in TS18.1. Figure 25 provides an overview of the improved facility control enhancement, showing the price ranges and corresponding facility control modes.

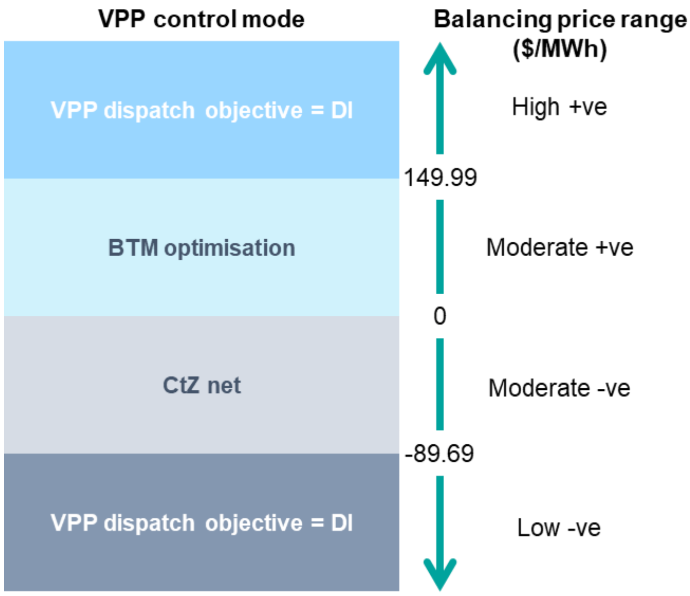

Figure 25: Improved facility control enhancement overview[85]

Testing revealed successful control of the VPP when price was below -$100 per MWh and when price was positive but failed in using the Constrain to Net Zero control measure when the price was in the moderately negative region. However, the issue was resolved during test case TS21.1.[86]

In terms of DOE publishing and compliance, the test case revealed successful creation and publishing of DOEs. Breaches to DOE export limits occurred on five out of six days, in approximately 0.2% of all intervals. However, DOEs are only considered binding when the DER export is constrained by the DOEs, which only occurred in 0.27% of all intervals. To counter this, simulated network constraints were used to publish binding DOEs, which revealed a 55% non-compliance rate.[87]

TS18.2 BMO with Constrained and Unconstrained DOE: Addition of Third-Party Aggregators

Over the week of testing, the VPP facility averaged below its dispatch targets. When the balancing price was between -$89.69/MWh and $149.99/MWh, the VPP optimised its dispatch BTM and did not respond to dispatch instructions, resulting in under-delivery of energy. Outside of this range, the VPP moved closer to reaching its targets. For TPAs, testing revealed an inability to respond to dispatch instructions as a separate facility under the VPP.[88]

TS19.1-19.2 BMO and ESS-CR with Constrained and Unconstrained DOE

The Pilot demonstrated the potential for orchestrated DER to be used to provide Contingency Reserve Raise services, however, the average valid response rate was only 35%. Additionally, the Pilot experienced issues in fulfilling the WEM requirements of Contingency Reserve Raise, with the valid responses exceeding the bid and total responses being lower than the bid.[89]

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[85] Western Power, Synergy, & AEMO, 2023b. *Project Symphony: Data Analysis Report Cycle 1*, p. 13
[86] Western Power, Synergy, & AEMO, 2023b
[87] Western Power, Synergy, & AEMO, 2023b
[88] Western Power, Synergy, & AEMO, 2023c. *Project Symphony: Data Analysis Report Cycle 8*
[89] Western Power, Synergy, & AEMO, 2023d. *Project Symphony: Data Analysis Report Cycle 4*

When tested in conjunction with the Balancing Market, both valid and total responses were well below the required capacity, with the Pilot demonstrating the response of the VPP for Contingency Reserve Raise degrading significantly on overcast days. Finally, it was found that using orchestrated DER for Contingency Reserve Raise significantly increases the risk of non-compliance with DOEs.[90]

TS20.1 Full Value Stacking with Constrained DOE

Testing revealed a tendency for the VPP to under-deliver energy in the Balancing Market, though this has been attributed to inaccurate forecasting and difficulty in submitting accurate variations, with the greatest discrepancy seen to occur just prior to NSS dispatch intervals. The valid response rate for Contingency Reserve Raise services increased from previous testing to 44%. There were also challenges in validating NSS provision. However, the Pilot did demonstrate the use of a VPP in interacting with the market via a dispatch profile, containing bids for energy, Contingency Reserve Raise, and NSS. It also demonstrated a VPP's capabilities in responding to dispatch instructions and optimising delivery across all three services. Despite this, testing revealed the VPP was unable to react to price signals effectively and update its bid in the market, requiring a more automated re-bidding capability to better leverage forecast updates.[91]

TS20.2-20.4 Full Value Stacking with Constrained DOE: Addition of Third-Party Aggregators

The Pilot data reveals a positive impact in the Balancing Market test scenario when assets contracted under a third-part aggregator are included in the orchestrated asset mix. The VPP demonstrated capability to take advantage of prices outside of the BTM optimisation band (-$89.69/MWh to $149.99/MWh) and consistently over-provided energy with reduced error between dispatch instructions and actual energy provided. This is in comparison to the VPP without third-party aggregator assets, which consistently under-delivered on energy with a greater margin of error. Due to contracts with TPAs specifying the use of assets for the provision of energy only, third-party aggregator integration was not tested for the provision of Contingency Reserve Raise or NSS. Future testing could focus on expanding third-party aggregator capabilities, providing access to greater value.[92]

In providing Contingency Reserve Raise, when batteries had sufficient charge, the VPP was able to exceed the nameplate inverter capacity in response to signals. However, the need to orchestrate batteries to have sufficient charge was a key learning during this testing week, as batteries were often discharged prior to a contingency event and unable to adequately provide Contingency Reserve Raise. Testing also demonstrated the VPP being capable of providing Contingency Reserve Raise simultaneously with NSS through orchestrating different assets. Regarding NSS, though the VPP successfully demonstrated capability in providing the service, it had similar issues as Contingency Reserve Raise with batteries requiring further management to ensure they are kept at adequate state-of-charge.[93]

TS20.5-20.7 Full Value Stacking with Constrained DOE: Addition of Third-Party Aggregators and Front-of-Meter DESS

Testing demonstrated successful market operation and clearing of the VPP in the Balancing Market for both load and generation, whilst simultaneously being dispatched for both Contingency Reserve Raise and NSS. The inclusion of a commercial BTM battery system and grid connected community battery, with capacities of 0.25MW and 1MW respectively, enabled a maximum injection capacity of 2.93MW and battery withdrawal of 1.78MW from the VPP. This also had a positive impact on the VPP's capability in meeting generation

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[90] Western Power, Synergy, & AEMO, 2023e. *Project Symphony: Data Analysis Report Cycle 5*
[91] Western Power, Synergy, & AEMO, 2023f. *Project Symphony: Data Analysis Report Cycle 6*
[92] Western Power, Synergy, & AEMO, 2023g. *Project Symphony: Data Analysis Report Cycle 11*
[93] Western Power, Synergy, & AEMO, 2023g

dispatch instructions during peak evening periods when prices are high for both the Balancing Market and NSS. However, despite showing capabilities in being dispatched for simultaneous services, the VPP still tended to under-deliver in both generation and load. Additionally, though the community battery was able to consistently capture market value through charge-discharge cycles, this value was not fully realised by the aggregator. The addition of the grid connected battery reduced overall dispatch compliance due to the aggregator's inability to update its boffer for large asset swings, impacting the overall value the aggregator receives and resulting in a net loss from its inclusion.[94]

A key finding was the inability of the VPP to respond to price signals during less extreme price events, with the VPP reacting poorly to market prices when in the BTM self-optimisation band or choosing not to provide a response to periods of low (non-volatile) pricing. Through testing of the Balancing Market, Project Symphony identified the high significance of real-time visibility through telemetry and its impact on the performance of each participant, for both on- and off-market services. Additionally, the aggregator's control and forecasting capability is equally important to intrinsic asset capability.[95]

Regarding Contingency Reserve Raise, both the commercial BTM battery and the community battery were able to respond to a real contingency event, with the commercial battery achieving a perfect droop response on top of BTM load discharge and the community battery achieving a 90% droop response. Due to their larger size, both the commercial battery and the community battery dominated the Contingency Reserve Raise service, as they were able to maintain sufficient charge late into the afternoon to continue responding to contingency events during the evening.[96]

Key learnings relating to the Contingency Reserve Raise service identified during testing included the dependency of the service on large DESS assets. Under the Pilot model, aggregators paid VPP participants to allocate a proportion of the DESS capacity, so it can bid and is able to respond to ESS-CRR events. Although residential BTM battery systems demonstrated capabilities to provide the service, an aggregator's decision on whether to submit a bid and offer for Contingency Reserve Raise depends on how they optimise for the services they provide and when orchestrated across the full value stack, whether they have sufficient capacity or charge to provide Contingency Reserve Raise, if used for NSS and self-optimisation.[97]

TS21.1-21.2 Constrain to Zero (Net and Gross)

The Pilot successfully tested the capabilities of the VPP in constraining DPV to both net and gross zero, with net Constrain to Zero seeing an 86 to 97% response rate and gross Constrain to Zero a 93 to 98% response rate. However, there were a larger number of assets included in the net scenario due to hybrid inverters not being included in the gross scenario, and some DPV systems not being included due to precautions relating to asset health. The gross scenario also did not include constraining batteries simultaneously as constraining solar, allowing batteries to discharge when DPV systems were curtailed, offsetting curtailment. As such, additional testing was conducted to include a modified gross Constrain to Zero functionality, allowing batteries and hybrid inverters to be constrained to zero.[98]

Overall, gross Constrain to Zero provided a similar outcome as net Constrain to Zero using fewer assets and through a much simpler control mechanism, but with a greater impact per customer from lost or used energy. As such, the net Constrain to Zero service holds considerable potential, providing customers with a more

[94] Western Power, Synergy, & AEMO, 2023h. *Project Symphony: Data Analysis Report Cycle 13 & 14*
[95] Western Power, Synergy, & AEMO, 2023h
[96] Western Power, Synergy, & AEMO, 2023h
[97] Western Power, Synergy, & AEMO, 2023h
[98] Western Power, Synergy, & AEMO, 2023i. *Project Symphony: Data Analysis Report Cycle 2 & 3*

palatable response compared to the current ESM in place, though the gross service resulted in a greater load on the network.[99]

The test also saw an improvement in compliance with binding DOEs compared to TS18.1, with non-compliance having reduced from 55% to 37% of intervals.[100]

TS22.1 Constrain to Zero with Battery included in Gross Service, Constrained DOE and NSS

To test the Constrain to Zero gross service with batteries included, the service was split into two separate services:

- BTM Assist.
- Zero Assist.

The BTM Assist service was the original service, constraining DPV assets to achieve zero generation. The Zero Assist service focused on constraining both DPV and batteries to ensure full curtailment of solar generation and zero battery discharge to achieve a load at the connection point. In comparing net Constrain to Zero and the two gross services, testing demonstrated the net service as achieving a significant reduction in generation export; the BTM Assist service resulting in facility output as close to or below zero; and the Zero Assist service achieving load at the facility aggregate level. Based on this, it was found that, from a network perspective, the Zero Assist service has the highest potential value with possible application in System Restart services. However, the net service remains better suited for sites that only have a DPV system and no available battery.[101]

[99] Western Power, Synergy, & AEMO, 2023i
[100] Western Power, Synergy, & AEMO, 2023i
[101] Western Power, Synergy, & AEMO, 2023j. *Project Symphony: Data Analysis Report Cycle 7*

3.6 Commercial Framework

Figure 26 shows the interactions between parties in Project Symphony, with the labelled interactions identifying those requiring commercial agreements. These interactions include those occurring solely within the Pilot and those expected to occur in a fully operational and scaled VPP. However, it is important to note that the commercial constructs used in the Pilot were designed to accelerate customer recruitment over commercial viability considerations. As such, learnings from the Pilot and CBA are expected to shape the form these commercial arrangements take in a scaled DSO/DMO model across the SWIS.

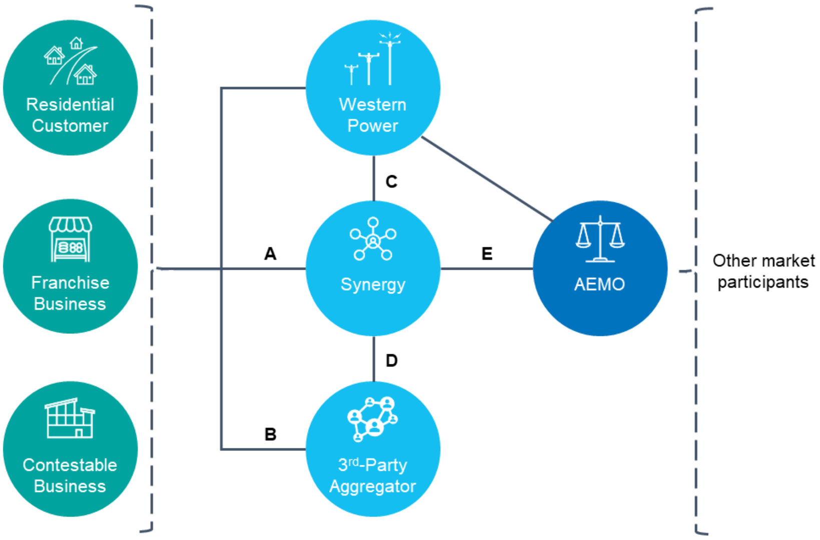

Figure 26: Commercial framework[102]

More information on the commercial framework used in Project Symphony can be found in the *Commercial Agreements Summary*[103] report.

[102] Adapted from: Western Power, Synergy, AEMO, & EPWA, 2021. *Project Symphony: Commercial Agreements Summary*
[103] Western Power *et al.*, 2021

4. Project Symphony Cost Benefit Analysis

Cost benefit analysis (CBA) is a valuation tool used to quantify the costs and benefits delivered by a project. It aims to monetise as many costs and benefits as possible relating to the modelled period, providing a final valuation of the project in financial terms. It also considers factors such as opportunity cost by comparing the net benefits across different modelling scenarios and testing the sensitivity of the results to changes in a range of variables. To do this, a project's expected total benefits are compared to its expected total costs using discounted cashflows (DCF) in each year. This is used to determine the net benefits provided in each year, across a specified timeframe, which are then discounted using an appropriate discount rate to determine the net present value (NPV) of the project. The costs and benefits that are unable to be monetised are also documented to ensure they are not ignored.

In the context of Project Symphony, a CBA study has been undertaken to quantitatively assess outcomes from the Pilot to understand the value DER orchestration can provide to the WA electricity industry and consumers.

As part of the funding arrangement of Project Symphony, the project partners are required to publish various knowledge-sharing deliverables. This CBA report, as the CBA of Project Symphony, serves as the ARENA knowledge-sharing deliverable for Project Symphony (work package (WP) 8.3), and leverages knowledge-sharing deliverables published as part of previous work packages to provide context and build on learnings, with particular focus given to WP 2.1, the DER Services Report, and WP 2.3, the DER Service Valuation Report. Further discussion on the various work packages, including the knowledge-sharing deliverables required by ARENA, is provided in the Appendices.

4.1 Objectives of Project Symphony's CBA

The CBA for Project Symphony includes four broad objectives.

The first is to quantitatively assess the costs and benefits of each participant in the Pilot in relation to the four test scenarios (discussed in section 3.3).

The CBA's second objective is to identify whether any barriers exist that prevent equitable distribution of value across the Pilot stakeholders: AEMO, Western Power, Synergy, TPAs, and Customers. Additionally, the CBA is to outline recommendations to remove these barriers, ensuring an optimised and equitable value distribution.

The third objective is for the CBA to scale the findings of the Pilot to the entirety of the SWIS, providing a quantitative analysis of these scaled costs and benefits within a three-to-ten-year period, and show how this value may be distributed.

Finally, the CBA seeks to provide high-level recommendations for achieving the requisite scale and value of future DER orchestration via a VPP within the WEM. As part of these recommendations, the CBA will provide insight relating to the conditions under which the benefits of a VPP to orchestrate DER outweigh the costs, where optimal value from DER can be realised, and any recommendations to explore other potential benefits of DER orchestration that were not included in the scope of the CBA or Pilot.

4.2 Limitations of the CBA Approach

The scope of the CBA is focused on the quantitative analysis of the four test scenarios considered within the Pilot and an area of the SWIS that had a high penetration of DER that could be recruited to participate within the Pilot. As such, it does not provide a valuation of DER orchestration from a whole of system perspective. Though commentary has been provided on various out-of-scope use cases and services, the potential value of these have not been quantified, nor represented, within the financial modelling of the CBA.

Project Symphony orchestrated residential customer DER assets, including DPV systems, BTM batteries, air conditioner systems, and electric hot water systems; one commercial property's DPV system and BTM battery. Whilst Western Power's grid connected community battery and the commercial DPV and DESS battery were included in the latter stages of the Pilot's stability period, these assets, together with hot water systems and air-conditioner systems were not included in the CBA's modelling due to the lack of statistically significant data. In absence of these data points, some additional case studies have been included in section 6 to provide a qualitative commentary on potential benefits and applications that were unable to be quantified in financial terms. Additionally, though the Pilot successfully tested curtailment of air conditioner system load, issues relating to signal response, data capture and visibility meant testing was unable to be completed to the required level. Therefore, air conditioner systems have been included as an additional use case with a high-level, indicative assessment completed, and the quantitative analysis of the CBA focuses on the two DER listed below, with other DER considered through case studies:

- DPV rooftop solar.
- BTM battery storage.

As the new market only went live in October 2023, the wholesale market prices for services used in the CBA are based on historical prices from the old market. As such, Project Symphony provides a simulated market and the prices used are not forecasted wholesale prices of the market. Though this provides as accurate as possible prices for the new market, forecasted wholesale prices may differ from those used, impacting the results of the CBA. To minimise the risk this presents to the CBA, the sensitivity analysis considers changes to price assumptions and provides a NPV range rather than a single value.

4.3 CBA Methodology

The CBA was performed by Ernst & Young (EY), with the support of Gridcog and the project partners.

The CBA is a DCF model that is augmented to include the cost of establishing and operating the resources needed to support DER orchestration and estimating the direct benefits associated with this orchestration, such as the deferral of capital expenditure. Positive externalities were considered qualitatively, such as improved network reliability, however system benefits, such as energy affordability and whole of systems costs were not within the scope of the CBA.

The CBA requires techniques and / or assumptions to be employed to convert all costs and benefits into a common monetary unit indexed to a particular year. To do so, the CBA considered the cost and benefits of DER orchestration over a 10-year period, using the data inputs from the Pilot, published data and other inputs sourced directly from the project partners. These results were then extrapolated to estimate the potential the benefits of DER orchestration when delivered at scale across the whole of the SWIS over the same 10-year period.

The net benefits of a project are determined by subtracting the present value of its total costs from the present value of its total benefits.

A positive net present value (NPV) implies that the investment is expected to deliver a positive outcome relative to the base case and warrants further consideration of investment.

The CBA considered the material cost and benefits of DER orchestration within the Pilot, from the perspective of the project partners and inputs associated with DER orchestration data was sourced from each of the project partners, using a combination of historical customer consumption data in the Pilot area, data generated during Project Symphony and other supporting stakeholder inputs and assumptions. Proprietary software developed by Gridcog was used to simulate market activity across the Pilot area and forecast cash flows and energy flows over a 10-year time horizon, providing a key input into the DCF modelling. Figure 27 shows this relationship, providing an overview of the CBA methodology employed.

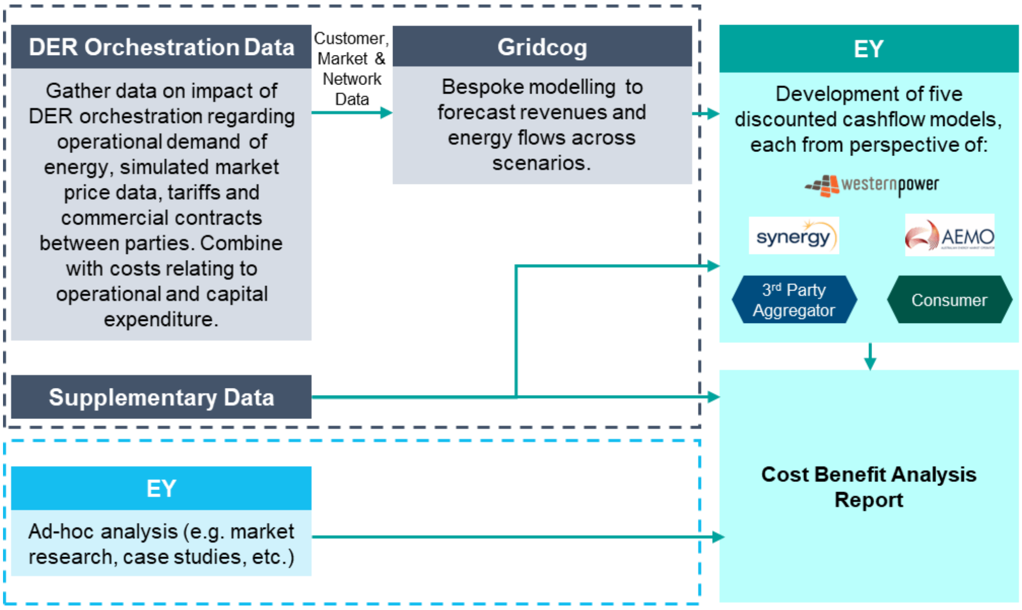

Figure 27: Overview of CBA methodology

The CBA was conducted using the following six-step approach:

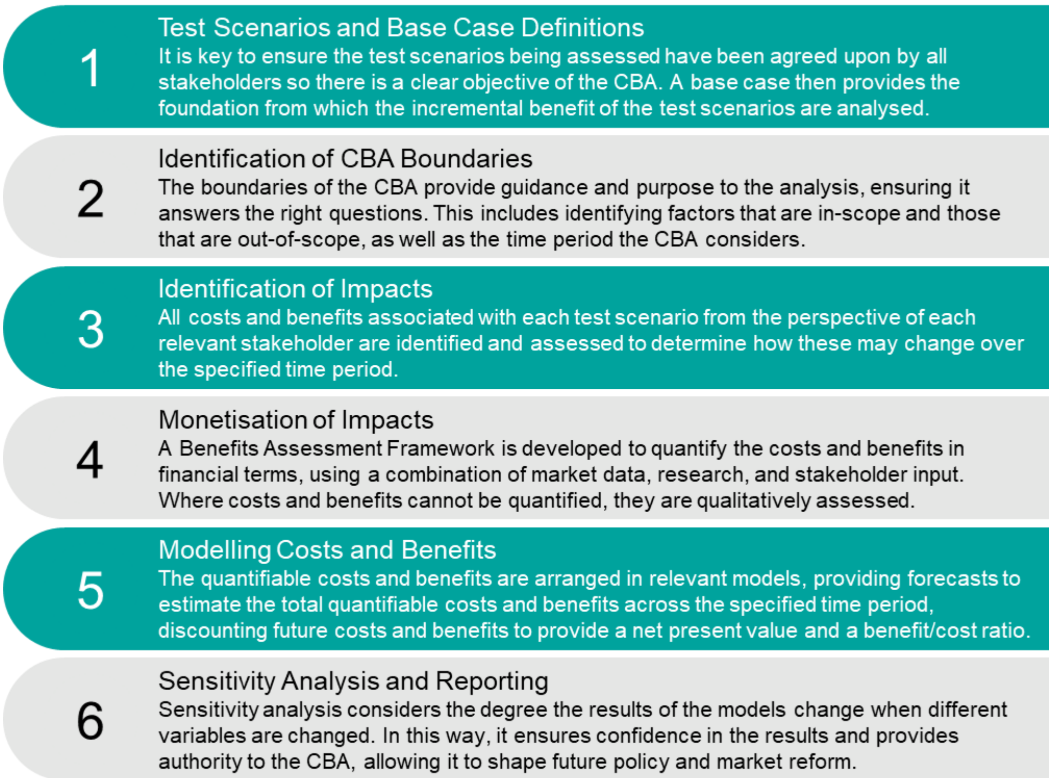

Figure 28: CBA six-step approach

For each of these steps, input from the project partners was obtained to validate the inputs and assumptions as a reasonable basis for the CBA model and subsequently documented (see section 4.4). The key stakeholders consulted included the core Project Symphony team and nominated subject matter experts from each project partner.

The outcome of the first step of the approach outlined above has been provided in section 3.3. Summaries of the output from the subsequent steps appear below, with the reporting of modelling results and sensitivity analysis outlined in sections 5 and 6.

4.3.1 CBA Boundaries

The boundaries of the CBA ensure the analysis is focused on answering the right questions to achieve its objective to assess the value DER orchestration creates, both now and in the future, with consideration given to the needs of customers and the network.

Table 3 lists the elements that have been included in the CBA and Table 4 lists those that have been excluded.

In Scope
• Development of DCF models for each actor in the Pilot (Aggregator, DSO, DMO, residential customers and TPAs) extrapolated over a 10-year time horizon, using revenue and costs incurred during the Pilot and simulated market conditions and forecast prices based of the WEM balancing price.
• Capex incurred by Pilot participants in the development, deployment and integration of technology platforms or tools built for the Pilot and delivering the VPP at scale over 10 years
• Opex incurred by Pilot participants associated with the maintenance and operation of the Pilot and delivering the VPP at scale over 10 years
• CBA for the following four test scenarios and distribution of revenue and costs across each actor: ○ Bi-directional Energy – Balancing market ○ Network Support Services ○ Constrain to Zero ○ Essential System Services – Contingency Reserve Raise
• Assessment of revenue and costs and distribution of value for each Pilot participant, under a “value-stacking” scenario where the four test scenarios are co-optimised
• Extrapolation of 12 months of actual load curves (metering data) for customers recruited to the VPP Pilot
• Modelling of customer owned DPV and residential BTM batteries (DESS) recruited in the Pilot
• Inclusion of cost to Synergy to offload excess solar generation during negative price periods, in the base case, NSS, CTZ and ESS-CRR test scenarios.
• Avoidance of short run marginal cost of generation activated during peak demand periods, due to aggregated DER via orchestration
• Deferral of network investment including zone substation augmentation, distribution transformer and feeder augmentation, due to aggregated DER via orchestration

Table 3: Elements in-scope of the CBA

Out of Scope
• Any impacts from regulatory changes, including future market and policy reform, beyond year three.
• Discounted cashflow modelling of costs and benefits associated with contestable customers.
• Any impacts to the value generated by orchestrating DER arising due to technological advancements.

- Modelling of the following DER assets due to data availability and reliability issues or exclusion from the Pilot:[104]
  - EV
  - Commercial and grid connected batteries
  - Air conditioner load control
  - Hot water load control
  - DOEs enabling larger DER
  - Greenhouse gas emissions
- Costs attributed to Synergy's retail, generation and wholesale business units that are not considered within the Pilot.
- Assessing the value of aggregated DER participating in the STEM or RCM or providing energy services to FCESS regulation raise and lower, and FCESS contingency reserve lower markets.
- Whole of system market modelling and quantification of whole of system economic benefits. The CBA is constrained to the four test scenarios and only considers factors directly connected to them.
- Recovery of costs, lost revenue or distribution of benefits through regulatory instruments e.g., changes to market participation fees and network tariffs.
- Any capital expenditure (capex) associated with asset replacement over the operational period of the model (the modelling includes the initial capex over the first three years and opex associated with maintenance of assets thereafter).
- Any impacts of changing stakeholder and customer behaviour / support due to changes to taxation.

Table 4: Elements out-of-scope of the CBA

4.3.2 Identification and Monetisation of Impacts

To identify and monetise benefits, a Benefits Assessment Framework was developed, assessing the net benefits (benefits minus costs) of Project Symphony that can be measured. The monetisation of as many costs and benefits as possible allows these impacts to be easily scaled to represent DER orchestration across the SWIS, providing a net financial value of the Pilot which can then be discounted to determine the NPV. However, as not all costs and benefits can be monetised, a qualitative assessment of benefits is provided within the commentary of results but is not considered in the discounted cashflow models.

Classifications

The two types of costs and benefits described above are referred to as tangible benefits (those that can be monetised) and intangible benefits (those that cannot be monetised). Table 5 lists the classifications of the tangible and intangible benefits considered in the CBA.

Category	Type	Example
Tangible	**Revenue Growth:** An increase in gross revenue from either an existing benefit or the realisation of a new benefit, either as a once off or recurring.	Gross revenue growth from product streams.
Tangible	**Cost Avoidance:** The removal or deferral of capital expenditure (capex).	Avoided or deferred cost of WEM investments, such as Network

[104] A qualitative assessment of out-of-scope use cases and case studies is provided in section 6.6 and 6.7

		investment avoided or deferred due to NSS.
Intangible	**Strategic Benefit:** A benefit that cannot be directly assigned a risk or financial value, but links to a strategic objective.	Increased customer satisfaction.

Table 5: Benefit categories for the benefit assessment framework

The identified costs and benefits are organised under their respective cost and benefit streams and analysed as a comparison between the base case test scenario and other test scenarios.

Overview of cost and benefit streams

The cost and benefit streams included in the CBA model are outlined in Table 6 and provides a description of the costs and benefits, and how the information provided by the project partners has been used.

Stream	Cost / Benefit	Application in the CBA
Pilot Set-Up Costs	Capex associated with Project Symphony, such as platform development costs and installation of advanced metering infrastructure.	Dollar value as reported in project financial reports.
	Opex associated with Project Symphony, such as labour costs and platform operation costs.	Dollar value as reported in project financial reports.
Distribution Networks	Benefit of distribution network investment avoidance or deferral due to reduced peak demand.	Dollar value calculated as the reduction/deferral of network investment based on reduced substation utilisation arising from lower peak demand.
	Capex associated with scaling the DSO Platform, such as installation of assets and additional platform development.	The average cost of developing the DSO Platform on a per DER asset basis, as determined by the reported cost of the build during the Pilot, combined with the expected number of DER assets in the SWIS, with the cost assumed to be incurred in year 1 and no ongoing capex.
	Opex associated with scaling the DSO Platform, such as platform maintenance and labour.	The sum of a fixed cost relating to software licencing and a variable cost determined by the average reported cost of opex related to the DSO Platform during the Pilot on a per DER basis, combined with the expected number of DER assets in the SWIS. From year four onwards, the cost decreases to only the fixed cost to show benefits of scale.
Generation	Benefit of generation investment avoidance or deferral due to DER orchestration removing the need to build additional generation.	Dollar value determined by the annual increase in operational demand compared to the annual increase in generator capacity and valued as the average generation build-out costs for the relevant size generation plant.
	Benefit of reduced cost of generation.	Dollar value of operations and maintenance costs of marginal generation units during peak, factoring in changes from deferred or avoided warm up costs, maintenance and fuel.

Stream	Cost / Benefit	Application in the CBA
DER Aggregation	Capex associated with scaling the Aggregator Platform, such as additional platform development and installation of assets.	The average cost of developing the Aggregator Platform on a per DER asset basis, as determined by the reported cost of the build during the Pilot, combined with the expected number of DER assets in the SWIS, with the cost assumed to be incurred in year 1 and no ongoing capex.
	Opex associated with scaling the Aggregator Platform, such as platform maintenance, labour, customer acquisition costs and other "costs to serve".	Dollar value determined by the reported cost structure on a per DER basis and combined with the expected number of DER assets in the SWIS and utilising a tiered structure to show benefits of scale.
	Revenue from WEM market services and non-market services.	Gridcog revenue modelling output.
	Changes in customer electricity bills.	Gridcog revenue modelling output.
Out-of-Scope Use Cases	Decreased GHG Emissions	Market research and case studies.
	Viability of grid connected batteries	Market research and case studies.
	Value provided by EV orchestration	Market research and case studies.
	Value provided by hot water control	Market research and case studies.
	Value provided by DOEs in enabling larger DER in the SWIS	Market research and case studies.
Regulatory and Policy Reform	Reduced reputational risk of not meeting high priority stakeholder expectations.	Risk rating reduced from Medium to Low, as identified via Project Symphony's Risk Management Framework.
	Costs of complying with laws, regulations, and administration.	The dollar value of costs associated with complying with relevant laws and regulations.
Market Structure	Capex associated with scaling the AEMO Platform, such as further integration with existing on-market platforms and additional platform development.	The average cost of developing the AEMO Platform on a per DER asset basis, as determined by the reported cost of the build during the Pilot, combined with the expected number of DER assets in the SWIS, with the cost assumed to be incurred in year 1 and no ongoing capex.
	Opex associated with scaling the AEMO Platform, such as platform maintenance and labour.	The sum of a fixed cost relating to software licencing and a variable cost determined by the average reported cost of opex related to the AEMO Platform during the Pilot on a per DER basis, combined with the expected number of DER assets in the SWIS. From year four onwards, the cost decreases to only the fixed cost to show benefits of scale.
	Increased DER participation via the implementation of a DER marketplace, resulting in increased visibility and control of DER and efficiently supporting the management of power system security and reliability.	A DER marketplace is developed and AEMO and DER capabilities are demonstrated as able to deliver an operational DER orchestration model, using market signals to incentivise DER behaviour.

Stream	Cost / Benefit	Application in the CBA
	Increased efficiency of the WEM with an increase of energy traded through it (versus energy seen as negative load), and increased competition for wholesale services.	The dollar value of total electricity traded in the WEM as determined by forecasted market prices across the time horizon.

Table 6:Overview of cost and benefit streams and respective assessment methodology

4.3.3 Discounted Cashflow Analysis

DCF analysis was used to assess the NPV of expected cashflows arising from Project Symphony's solution when scaled to the SWIS. In the context of this report, the chosen discount rate is Western Power's weighted average cost of capital (WACC) determined by the Economic Regulation Authority, which reflects the project's cost of financing. DCF cashflows were developed for each project stakeholder across the four test scenarios when operated in isolation of each of the other services, and modelling scenarios described in section 4.5, as well as an additional unorchestrated DER base case scenario and a Fully Orchestrated scenario.

It is important to note that the Pilot testing completed within Project Symphony sought to test a representative range of capabilities across the four scenarios, which included the value stacking of NSS and ESS-CR on top of the Bi-directional Balancing Market scenario, as opposed to testing these scenarios in isolation of each other. The constrain to zero scenario, which is an emergency "off-market service" was tested independently of the Bi-directional Balancing Market scenario.

4.3.4 DCF Cost and Revenue Categories

Cost and revenue cashflows were grouped within the DCF model for each project stakeholder. A summary of the cost and revenue categories and high-level description of each category is provided in Table 7.

Stakeholder	Category	Description
Synergy	Retail	Revenue received from residential retail tariffs (A1 and Midday saver *less* The cost of REBS/DEBS paid to customers for solar exported to the grid
	Network	Revenue received from Western Power for NSS *less* The cost of network tariffs paid to Western Power for the transport of electricity to customers
	Capital expenses	Capital expenditure incurred during the Pilot (including Aggregator Platform costs and communications devices) *plus* Forecast capital expenditure required to scale the Aggregator Platform to the rest of SWIS
	Operating expenses	Ongoing operating expenses related to Pilot and management of the aggregator function when scaled to the rest of SWIS *plus* Incentives and DPV orchestration payments paid to recruit customers to the VPP *plus* The cost of subsidies paid to customers to offset the purchase of DESS

Stakeholder	Category	Description
		(during Pilot only)
	Generation costs	Marginal cost of generation units during peak demand period
	WEM balancing energy	Revenue earned from the sale of electricity to the WEM Balancing Market *less* The cost of purchasing balancing energy from the market *less* The opportunity cost of paying a market participant to *"take"* excess solar that has been exported to the grid that exceeds demand, at a negative balancing price
	Market fees and services	Market fees paid to AEMO *less* Revenue received from AEMO for Essential System Services – Contingency Reserve Raise services
	TPA payments	Payments to the TPA to provide access to TPA resources
Western Power	Network revenue	Revenue received from Synergy network tariffs for energy imported from the grid *less* NSS fees paid to Synergy including a biannual availability fee and energy cost $/MWh
	Capital expenses	Capital expenses incurred during the Pilot including the development of the DSO Platform *plus* Capital expenditure identified within the 10-year business plan associated with the continued management of the DSO functionality within the context of the VPP *plus* Forecast capital expenditure for network augmentation including additional zone substations and transformers, distribution transformers and feeder augmentation
	Operating expenses	Operating and project management expenses incurred during the Pilot *plus* Ongoing operating expenses related to Pilot and management of the DSO when scaled to the rest of SWIS
AEMO	Market costs	Energy purchased from the wholesale electricity market that flows through the market operator
	Capital expenses	Capital expenditure incurred during the Pilot including development of the "off-market" DMO Platform costs
	Operating expenses	Ongoing operational expenses related to Pilot and forecast DMO costs to scale the VPP to the rest of SWIS
	System costs	LFAS regulation costs and purchase of a Non-Co-optimised Essential System Services (NCESS) minimum demand service to mitigate unmanaged DER

Stakeholder	Category	Description
	Synergy energy costs and market fees	Revenue received from Synergy for energy purchased from the wholesale electricity market, that flows through the market operator *plus* Revenue received from for market registration fees *less* The cost of Essential System Services – Contingency Reserve Raise fees paid to the Synergy
Customer	Capital expenses	The cost of purchasing DER and communications devices required to participate in the VPP
	Energy import and export costs	Revenue received from REBS/DEBS solar exported to the grid *less* The cost of importing energy from the grid
	Aggregator payments (Synergy)	Incentives and DPV orchestration payments paid to recruit customers to the VPP
	TPA payments (Synergy)	Payments received from TPAs to participate within the VPP
TPA(s)	VPP participation	Payments to DER customer enrolled by a TPA to participate within the VPP
	Operating expenses	Ongoing operating expenses related to the management of the TPA aggregator platform and participation in the VPP
	Aggregator payments (Synergy)	Payments received from Synergy to TPA to provide access to TPA resources

Table 7: Cost and revenue categories

Whilst a DCF model was developed for each project stakeholder to capture the revenue and costs attributed to their respective role in DER orchestration, the benefits of a VPP are expected to transcend the project stakeholders and deliver a benefit to the whole of the SWIS, irrespective of whether customers own a DER or choose to participate within a VPP. As such, the results discussed in section 5 reflects the NPV for the combined project stakeholders and difference in cashflows between the base case and test scenario.[105]

4.4 Assumptions

In consultation with Project Symphony partners, a range of assumptions were developed to support development of the CBA. This included model input assumptions, general modelling assumptions, network assumptions, retail and generation assumptions, orchestration assumptions, DER asset assumptions, and test case specific assumptions. Key assumptions are outlined in the tables below.[106]

Assumption	Description	Value

[105] Note: The CBA model containing the detailed cashflow analysis to determine the net NPV for each project stakeholder is separate to this report.
[106] All assumptions without a specified source were provided by the Project Symphony partners.

Assumption	Description	Value	
WACC	The nominal weighted average capital cost used to discount future costs and benefits to a present value.	7.02%[107]	
Population Growth	The 10-year compound annual growth rate for dwellings (with one dwelling resulting in one service connection) in the SWIS.	1.85%[108]	
DPV Growth	The year-on-year growth rate of residential DPV in the SWIS, over 10 years.[109]	2023-24	9.2%
		2024-25	8.4%
		2025-26	7.7%
		2026-27	8.5%
		2027-28	8.6%
		2028-29	7.7%
		2029-30	7.0%
		2030-31	5.6%
		2031-32	5.0%
		2032-33	4.7%
Battery Growth	The year-on-year growth rate of distributed Energy Storage Systems (DESS) e.g., residential and commercial batteries in the SWIS, over 10 years.[110]	2023-24	85.5%
		2024-25	84.2%
		2025-26	49.0%
		2026-27	34.3%
		2027-28	27.4%
		2028-29	24.1%
		2029-30	25.7%
		2030-31	17.3%
		2031-32	13.8%
		2032-33	14%
VPP Participation	The VPP participation rate in each modelling scenario was calculated as a percentage of the total number of DER owners eligible to join a VPP.	Refer to Table 19	

Table 8: List of modelling input assumptions

[107] Economic Regulation Authority, 2023a. *Final decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*
[108] AEMO, 2023a.
[109] AEMO, 2023a. Expected growth forecast of residential DPV from the 2023 ESOO.
[110] AEMO, 2023a. Expected growth forecast of DESS from the 2023 ESOO.

No.	General Assumptions
1	Nominal values have been used in the modelling and have not been adjusted for inflation.
2	Market revenues repeat every year over the lifetime of the asset / enrolment in the VPP.
3	All costs and revenue data provided in the simulated markets are representative of the future live market.
4	Tax has not been considered in the modelling.
5	Registered Life Support Equipment (LSE) customers are excluded from potential VPP recruitment candidates. Residential LSE customers are approximately 0.3% of the total customer base in the SWIS.

Table 9: General modelling assumptions

<table>
<tr><th>No.</th><th colspan="8">Network Assumptions</th></tr>
<tr><td>1</td><td colspan="8">Network charges are applied after dispatch optimisation and calculated on the metered energy consumption.</td></tr>
<tr><td>2</td><td colspan="8">A static 5kW export limit was used for single-phase connections and three phase connection for DPV ≤ 5kW and 1.5kW for three-phase connections > 5kW in the base case test scenario.</td></tr>
<tr><td rowspan="7">3</td><td colspan="8">The modelling applied the following DOEs, with one applied to forecast minimum demand threshold days and the day immediately following (over two consecutive days), and the other applied at all other times.[111]</td></tr>
<tr><td colspan="2" rowspan="2"></td><th colspan="2">12am – 10am</th><th colspan="2">10am – 3pm</th><th colspan="2">3pm – 12am</th></tr>
<tr><th>Import</th><th>Export</th><th>Import</th><th>Export</th><th>Import</th><th>Export</th></tr>
<tr><td rowspan="2">Minimum demand day</td><td>Single-phase</td><td>15kW</td><td>15kW</td><td>15kW</td><td>1.5kW</td><td>15kW</td><td>15kW</td></tr>
<tr><td>Three-phase</td><td>22.5kW</td><td>22.5kW</td><td>22.5kW</td><td>4.5kW</td><td>22.5kW</td><td>22.5kW</td></tr>
<tr><td rowspan="2">All other times</td><td>Single-phase</td><td>15kW</td><td>15kW</td><td>15kW</td><td>15kW</td><td>15kW</td><td>15kW</td></tr>
<tr><td>Three-phase</td><td>22.5kW</td><td>22.5kW</td><td>22.5kW</td><td>22.5kW</td><td>22.5kW</td><td>22.5kW</td></tr>
<tr><td>4</td><td colspan="8">There is no fee charged for embedded generation connections up to 30kVA, therefore DER connection revenue is not included in the modelling.</td></tr>
<tr><td>5</td><td colspan="8">Thermal and voltage impacts on MV distribution networks fall outside the 10-year time horizon of the CBA, so are not included in the modelling.</td></tr>
<tr><td>6</td><td colspan="8">All over-utilised zone substations, distribution feeders and distribution transformers must be augmented to provide additional capacity or require NSS to defer augmentation.</td></tr>
<tr><td>7</td><td colspan="4">A constant Transmission Loss Factor was applied to residential customers:</td><td colspan="4">1.0000</td></tr>
</table>

[111] DOE import and export limits will continue to evolve in consideration of design ADMD requirements. The impact of increasing the size of DPV systems and reducing DOE export limits is discussed in section 5.1.8.

No.	Network Assumptions	
8	A constant Distribution Loss Factor was applied:	1.0797
9	All residential customers are registered under the one network tariff:	RT1
10	One metering network tariff is used in the modelling to represent all customers:	M7

Table 10: Network assumptions

No.	Retail and Generation Assumptions
1	Capital expenditure in generation and subsequent maintenance and operation costs are derived from CSIRO's *GenCost 2022-23* report.[112]
2	Customer participation in the VPP has no impact on customers receiving the relevant feed-in tariff.
3	All customers currently receiving the REBS feed-in tariff continue to receive the REBS tariff across the 10-year time horizon of the modelling and all new customers (as per population growth forecasts) receive the DEBS feed-in tariff.
4	The A1 retail tariff is used in the modelling to represent all residential customers without a battery system.
5	The Midday saver retail tariff is used in the modelling to represent all residential customers with a battery system.

Table 11: Retail and generation assumptions

No.	Orchestration Assumptions
1	Operational expenditure relating to DER orchestration remains unchanged over the 10-year time horizon.
2	Customers who joined the VPP during the Pilot are assumed to have all been registered with assets fully orchestrated by commencement of the modelling period.
3	Subsidies provided to customers for purchase and installation of new assets (i.e., batteries) will not continue outside of the Pilot environment.

4	The incentive and orchestration payments made by Synergy to customers for the Pilot, except for subsidies, continue for the duration of the 10-year time horizon of the modelling. This includes:
	• $150 per asset paid annually on a pro-rata basis for all customers participating in the VPP, and
	• For customers with DPV but no battery, an annual pro-rata orchestration payment, based on the size of the DPV system:
	    o For systems 2kW or less, $310.30
	    o For systems above 2kW but less or equal to 3kW, $463.60
	    o For systems above 3kW but less or equal to 4kW, $613.20
	    o For systems above 4kW but less or equal to 5kW, $773.80
	    o For systems above 5kW, $773.80

[112] Graham, Hayward, Foster, & Havas, 2022. *GenCost 2022-23: Consultation draft*

5	The commercial agreements between Synergy and the TPAs participating in the Pilot are combined to determine the average payments between Synergy and a third-party aggregator, which is then used for the duration of the 10-year time horizon of the modelling.
6	The orchestration payments made by the TPAs participating in the Pilot to customers have been averaged and used for the duration of the 10-year time horizon of the modelling.
7	A single 'virtual' third-party aggregator is used in the modelling, representing the average costs and benefits of the three that participated in the Pilot.
8	The Pilot participants were required to be homeowners, to participate in the VPP. Given 69.2% of dwellings in the SWIS are owner occupied,[113] this criterion excludes some customers from receiving the benefits of DER (e.g., renters) and will require further consideration.
9	Where the Pilot utilised two vendors for services related to the platforms developed, the vendor with the lower cost was modelled.
10	The cashflows related to selling energy export from customer DPV systems into the market are recorded as a benefit for the Bi-directional Energy - Balancing Market test scenario and as a cost for all other test scenarios to recognise the cost Synergy incurs to manage of excess solar energy.

Table 12: Orchestration assumptions

No.	DER Asset Assumptions
1	DER have 100% compliance to signals, conforming to the VPP, with the VPP bearing the risk and cost of lack of firmness at the individual facility level.[114]
2	The expected life of DER assets will last for the duration of the 10-year modelling period.
3	DER assets are optimised to minimise the cost of the energy imports for customers, whilst maximising the benefit to Synergy.
4	DER capital expenditure incurred by customers is assumed to include installation costs.
5	Due to lack of available data, costs associated with maintenance and wear and tear of customer DER assets are not considered in the modelling.
6	The DER asset allocation for customers in the pilot are representative of the asset allocation of the VPP when scaled to the SWIS.
7	Each DER asset can only be used for one service at a time, requiring the VPP to optimise by allocating orchestrated assets to the various services modelled.
8	The number of residential customers with a DPV system at the commencement of the modelling period is 380,052.[115]
9	All new residential DPV assets installed in the SWIS have a capacity of 5kW across the 10-year modelling period.[116]
10	Solar panel orientation for all residential customers is set at 0°.

[113] Australian Bureau of Statistics, 2023. Regional population, 2021-22 financial year | Australian Bureau of Statistics (abs.gov.au)
[114] Pilot testing indicated that achieving 100% compliance is unlikely to be achieved in the real world due to device failure and issues regarding communications, and future modelling should consider a reduced level of compliance.
[115] Synergy, 2023c. *2023 DER register* (as of 30 June 2023)
[116] The implementation of DOEs, will enable larger capacity DPV systems to be connected to the distribution network. The CBA model extrapolated the average DPV size in the Pilot and did not consider variations in DPV capacity.

Project Symphony
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No.	DER Asset Assumptions
11	Solar panel tilt for all customers is set at the optimal angle for the greater Perth region 30°.
12	DPV system module inverter ratio for all residential customers is set at 1.33.
13	DPV systems experience losses of 11%.
14	The number of residential customers with a battery system with export capability at commencement of the modelling period is 2,941.[117]
15	The decrease in cost of residential batteries year-on-year is expected to follow the same percentage decrease as large-scale batteries, as identified in CSIRO's *GenCost 2022-23* report.[118]
16	All new residential battery assets installed in the SWIS have a capacity of 10kWh.
17	Battery systems for all residential customers, when controlled by the customer, operate with a maximum state of charge of 100%.
18	Battery systems for all residential customers, when controlled by the customer, operate with a minimum state of charge of 0%.
19	The maximum and minimum state of charge for batteries relates to the use of the batteries by the customers. The aggregator can only orchestrate the batteries within the constraints of a 10% minimum state of charge and a 90% maximum state of charge.
20	Battery systems for all residential customers operate with a self-discharge per day rate of 0.08%.
21	Battery system storage degradation rate of 2% per annum.
22	The round-trip efficiency of battery systems for all residential customers is set at 96-98%.

Table 13: DER asset assumptions

No.	System Cost Assumptions
1	The ESM and associated costs/benefits is not considered in the modelling.
2	DPV participating in the VPP are assumed to be "managed DPV", with all DPV not enrolled in a VPP categorised as "unmanaged DPV".
3	The cost of LFAS is calculated using the following equation: $$LFAS\ Cost = (\Delta UnmanagedDPV - \Delta ManagedDPV) \times Avg.LFAS\ per\ DPV\ MW\ \times \$LFAS/MW$$ Where $\Delta UnmanagedDPV$ is 308MW, as per the 2022 ESOO forecasts, $Avg.LFAS\ per\ DPV\ MW$ is 0.036MW, as per data for the 2020, 2021, 2022 and 2023 capacity years, and $\$LFAS/MW$ is $650,000, calculated as the average cost of the 2020 and 2023 capacity years. The full cost of LFAS is paid annually in June.

[117] Synergy, 2023c (as of 30 June 2023) - The total number of installed batteries in the SWIS is 9,471, however 6,530 do not have export capability. Only batteries with export capability are considered in the modelling
[118] Graham *et al.*, 2022

4	The cost of the minimum demand service (MDS) is calculated using the following equation: $$MDS\ Cost = MDS\ Availability + MDS\ Activation$$ Where, $$MDS\ Availability = Availability\ Price \times MDS\ Required$$ $$MDS\ Activation = Activation\ Price \times MWh\ of\ MDS\ Activated$$ And $$MDS\ Required = MDS\ Required\ per\ DPV\ MW \times (\Delta UnmanagedDPV - \Delta ManagedDPV)$$ $$MWh\ of\ MDS\ Activated = \frac{MDS\ Activated_{Base}}{MDS\ Required_{Base}} \times MDS\ Required$$ Where $\Delta UnmanagedDPV$ is 308MW, as per the 2022 ESOO forecasts, $MDS\ Required$ is the additional MDS capacity in MW procured by AEMO, with MDS following a 2-year cycle, resulting in additional MDS procured every two years, and $\frac{MDS\ Activated_{Base}}{MDS\ Required_{Base}}$ is the ratio of MDS activation in MWh to MDS required in MW of the relevant year in the base case test scenario.[119] The full cost of MDS is paid annually in June.

Table 14: System cost assumptions

No.	Bi-Directional Energy – Balancing Market Assumptions
1	The Balancing Market price for electricity for each 30-minute interval was determined using historical WEM prices.
2	All in-scope DER assets are orchestrated and co-optimised to participate in the Balancing Market.
3	DER assets are co-optimised for the aggregator and the customer to minimise the cost of the retail tariff for the customer, minimise the cost of the network tariff for the aggregator, and minimise exposure to high balancing prices for the aggregator, with equal weighting provided to each factor, and calculated to provide the maximum benefit.

Table 15: Balancing Market scenario assumptions

No.	Network Support Services Assumptions
1	Modelling of NSS considers the firm service contract and excludes flexible service.
2	Pricing of NSS follows the contract used in Project Symphony's Pilot.[120]
3	Due to DER capability constraints, NSS is provided by battery systems only. For this reason, batteries are assumed to be orchestrated to ensure sufficient charge to provide NSS for forecasted events, whilst allowing the batteries to be used for self-consumption.
4	All NSS events commence at 18:00 and have a duration of three hours to reflect peak evening periods.
5	Battery systems are controlled to ensure sufficient charge to dispatch for NSS, with forecasted events communicated to the aggregator 24 hours in advance.

[119] The MDS Activation Price and Availability Price are market-sensitive information and have been intentionally omitted.
[120] The price used in the existing contract reflects the commercial and procurement processes at the time the contract was established. Future pricing is subject to commercial and procurement processes at that time.

6	NSS events were forecasted using historical data from the Bureau of Meteorology, with an NSS event assumed to occur when the maximum temperature forecasted for that day was above 35°C and the minimum temperature forecasted for the day following was above 20°C.[121] As such, an average of 15 NSS events were assumed to occur annually.
7	Approximately 50% of distribution feeders that have a utilisation of 80% or greater, which equates to will require augmentation within 10-years and are potential candidates for NSS.[122]
8	NSS successfully defers distribution feeder augmentation for a period of 4 years. Forecast feeder augmentation costs are based on Western Power's Network Plan 2025
9	In relation to distribution transformers, every 15% of BTM battery participation (compared to total battery systems in the SWIS) results in 15% transformer peak load reduction, allowing 20% of distribution transformer investment to be deferred for 2 years.
10	The VPP is successfully dispatched for the full NSS requirement for every NSS event.

Table 16: Network Support Services scenario assumptions

No.	Constrain to Zero Assumptions	
1	The Minimum Demand Threshold is the trigger for Constrain to Zero:	700MW
2	The price of the Constrain to Zero service is the activation price paid for MDS, with cost of the service calculated as follows: $$CtZ\ Cost_{Month} = DPV_{VPP,m} \times Duration_E \times Activation\ Price$$ Where, $CtZ\ Cost_{Month}$ is the cost of Constrain to Zero for that month, $DPV_{VPP,m}$ is the total capacity of DPV orchestrated under the VPP for that month in MW, and $Duration_E$ is the duration of the Constrain to Zero event, assumed to be 4 hours, with a maximum of one event occurring in the month.	
3	Customers who opt-in to a VPP automatically consent for their DPV to be used for the Constrain to Zero service.[123]	
4	The Constrain to Zero service is assumed to address minimum demand concerns, reducing the MDS requirement in proportion to the available DPV energy (in MWh) orchestrated in the VPP, as shown: $$CtZ_{Year} = \sum_{m=1}^{E} DPV_{VPP,m} \times Duration_E$$ And, $$MWh\ of\ MDS_{CtZ} = MWh\ of\ MDS\ Activated - CtZ_{Year}$$ Where, CtZ_{Year} is the total Constrain to Zero service required for the year in MWh, $MWh\ of\ MDS_{CtZ}$ is the MDS activation required for the year in MWh after taking Constrain to Zero into consideration, and $MWh\ of\ MDS\ Activated$ is the original MDS activation required for the year in MWh if the Constrain to Zero service was not available.	
5	Forecasting of Constrain to Zero events was based on monthly minimum demand forecasts, resulting in: • Only one Constrain to Zero event in a month, where the minimum demand for that month was forecasted to be below the Minimum Demand Threshold. • For modelling purposes, a random day within the applicable month was assigned to each event.	

[121] Bureau of Meteorology, 2023. Climate Data Online - Map search (bom.gov.au) (accessed 2 August 2023).
[122] Western Power, 2022c. *Network Opportunity Map 2022*
[123] Though this assumption was held for the purposes of modelling, it is a policy decision that needs to be made by Energy Policy WA.

No.	Constrain to Zero Assumptions
	• Constrain to Zero events only required from August to December each year.
6	All Constrain to Zero events commence at 11:00am and continue for the whole four-hour duration, uninterrupted, to coincide with minimum demand periods.
7	Only the net Constrain to Zero service was modelled i.e., the curtailment of gross solar was not considered.
8	All DPV systems registered with the VPP are available for the Constrain to Zero service and are successfully dispatched for all events.

Table 17: Constrain to Zero scenario assumptions

No.	Essential System Services – Contingency Reserve Raise Assumptions
1	Pricing of the Contingency Reserve Raise service used the margin values for SRAS published in AEMO's *2023 Ancillary Services Report*[124] and ERA's equation for calculating the cost of SRAS: $$cr_t = \frac{m}{2} \times p_t \times q_t$$ Where cr_t is the Contingency Reserve Raise payment for interval t, m is the margin value, p_t is the balancing price at interval t, and q_t is the quantity provided at interval t.[125]
2	As Synergy is the only aggregator modelled, Contingency Reserve Raise payments: • Are calculated based on actual quantity dispatched at the relevant price. • Do not include an availability payment.[126]
3	Due to DER capability constraints, Contingency Reserve Raise is provided by battery systems only, with 2% of offered capacity not delivered. For this reason, batteries are assumed to be orchestrated to ensure sufficient charge to provide Contingency Reserve Raise at all times, whilst allowing the batteries to be used for self-consumption.
4	Forecasting of contingency events was based on the contingency risk associated with increasing DPV generation in the SWIS.
5	The VPP is successfully dispatched for the full Contingency Reserve Raise requirement for every contingency event.

Table 18: Contingency Reserve Raise scenario assumptions

4.5 Modelling Scenarios

The modelling scenarios reflect the variability of future conditions and provide a range for value generated via Project Symphony across the 10-year time horizon. To assist in determining the modelling scenarios, the CBA follows the Australian Energy Regulator's CBA guidelines, which outline the requirements AEMO is required to fulfil when developing the Integrated System Plan for the NEM. This includes consideration provided to the key inputs driving supply and demand conditions and major sectoral uncertainties, with the modelling scenarios developed by changing these inputs or to reflect the impact of the major uncertainties.[127]

[124] AEMO, 2023e. *Ancillary Services Report for the WEM*, p. 20
[125] Economic Regulation Authority, 2022b. *Spinning reserve, load rejection reserve, and system restart ancillary service settlement values 2022/23*, p. 9
[126] Economic Regulation Authority, 2023b. *Frequency co-optimised essential system services offer price ceiling determination*
[127] Australian Energy Regulator, 2020. *Cost Benefit Analysis Guidelines*

To provide consistency with other publications on modelling scenarios in the WEM, the approach used a consistent set of forecasts that were used in AEMO's 2023 WEM Electricity Statement of Opportunities (ESOO), published in August 2023. As such, the following key inputs were identified:

- DPV growth.
- Distributed battery storage growth.
- VPP participation.

The ESOO provides a highly detailed level of modelling and considers a range of factors that are relevant to a broader audience of market participants and consumers across WA. Though this level of whole of system modelling was not within the scope of this CBA, which focusses on extrapolating data from the Pilot area and Synergy as the sole market participant registered as an aggregator, although it engages with TPAs to increase the number of residential Pilot participants, the breakdown provided in the ESOO was determined to be useful in assessing the value of Project Symphony across the WEM.

To develop the modelling scenarios, key inputs were sourced from publicly available information, including forecasts for DPV and battery growth, and the forecasted growth of residential dwellings in the SWIS published in the 2023 WEM ESOO; and a level of VPP participation to assess the changes in value for each of the project participants as participation rate increases. From these, four modelling scenarios were created, which consider the impact of DPV and DESS growth over the 10 years and likelihood of DER owners participating within a VPP. Table 19 provides an overview of the four modelling scenarios.

Modelling Scenario	DPV Growth	Battery Growth	YoY addition of DER owners to the VPP	% of DESS joining the VPP
Pilot	7.2%	37.4%	5%	42%
Expected growth	7.2%	37.4%	10%	50%
High growth	8.7%	41.9%	30%	70%
Hyper growth	8.7%	53.3%	50%	100%

Table 19: Overview of modelling scenarios

The modelling was completed using a consistent set of assumptions and input values, provided in section 4.4, used during the Pilot. The *Pilot* scenario extrapolates these assumptions over a 10-year period to provide a basis on which the other modelling scenarios can be compared.

The average expected DPV growth (e.g., the number of DPV added to the SWIS), was based on the expected DPV growth case in the ESOO for the *Pilot* and *Expected growth* modelling scenarios, and the high case for the *High growth* and *Hyper growth* modelling scenarios. It should be noted, however, that the annual growth numbers were used in the modelling, which are provided in Table 8.

Similarly, the average annual battery growth from the ESOO was used to forecast the total number of batteries added to the SWIS each year. The annual expected battery growth rate was used for the *Pilot* and *Expected growth* modelling scenarios, and the high case for the *High growth* modelling scenario. It should be noted that the ESOO does not separate growth rates for residential and commercial batteries. For the *Hyper growth* modelling, an inflated growth rate was used to assess the impact of increased battery saturation. The required growth rate was calculated determining the required year-on-year growth to achieve 200,000 batteries by the end of the 10-year modelling period, less the number of batteries that have already been installed in the SWIS in year 2024. The growth rates also assume that DESS are not subsidised, however if offered, this could potentially increase the number of DESS in the SWIS further.

The number of DPV and DESS added to the SWIS at the start of each year for each modelling scenario is provided in Table 20.

Modelling Scenario		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Pilot	DPV	34,904	34,808	34,808	41,220	45,401	43,878	42,988	37,115	34,743	34,012
	DESS	2,941	2,514	4,591	4,920	5,135	5,512	6,161	8,181	6,921	6,452
Expected growth	DPV	34,904	34,808	34,808	41,220	45,401	43,878	42,988	37,115	34,743	34,012
	DESS	2,941	2,514	4,591	4,920	5,135	5,512	6,161	8,181	6,921	6,452
High growth	DPV	37,285	37,183	37,183	51,371	64,823	65,409	65,371	50,079	43,998	39,587
	DESS	2,941	1,943	5,656	6,036	6,653	7,652	9,141	11,879	10,421	9,759
Hyper growth	DPV	37,285	37,183	37,183	51,371	64,823	65,409	65,371	50,079	43,998	39,587
	DESS	2,941	1,537	2,341	3,564	5,427	8,264	12,583	19,160	29,175	44,424

Table 20: Number of DPV and DESS added to the VPP each year

To progressively add customers to the VPP, the modelling considered the available pool of participants in the SWIS that were not already participating within the VPP and any new additions of DER in each year, less the number of batteries that were being added each year.[128] The *Pilot* scenario assumed a 5% year-on-year participation rate increase, based on the number of participants recruited within the Pilot, although it is acknowledged that when delivered at scale the participation rate, if marketed and incentivised appropriately, would be higher. For the *Expected growth, High growth* and *Hyper growth* modelling scenarios, a distribution of values was used to assess impact of different participation rates. In addition to the VPP participation rate, the percentage of batteries added to the VPP each year compared to the number of batteries installed was considered. During the Pilot, 42% of the customers within the VPP owned DPV and a battery and the same percentage was used for the *Pilot* modelling scenario.

To reflect WP 2.1 *DER Services Report*,[129] which identified the importance of batteries in providing value from a VPP, acknowledging that batteries can provide a different service compared to DPV and could be incentivised to join a VPP, a higher battery participation rate was assumed in *Expected growth, High growth* and *Hyper growth* modelling scenarios using a distribution of values. As the VPP facility achieves a sufficient size and scale, it has the potential to become a dominant provider of energy services such as ESS-CRR, which will influence the structure of the market. Figure 29 and Figure 30 illustrates the size of the VPP aligned to the DPV and DESS growth and different VPP participation rates at the start of each year for each modelling scenario.[130]

[128] Registered Life Support Equipment (LSE) customers are approximately 0.3% of Western Power's customer connections and are eligible for VPP participation and have not been in the potential pool of VPP customers.
[129] Oakley Greenwood, 2022. *Project Symphony: DER Services Report*
[130] Capacity of DPV and DESS participating in the VPP includes systems already existing in the SWIS, with the capacity in the VPP recorded for each year the capacity at year-end of the calendar year. As such, each modelling scenario reflects different start points, though the minimal existing capacity of DESS in the SWIS means this is less pronounced than DPV capacity.

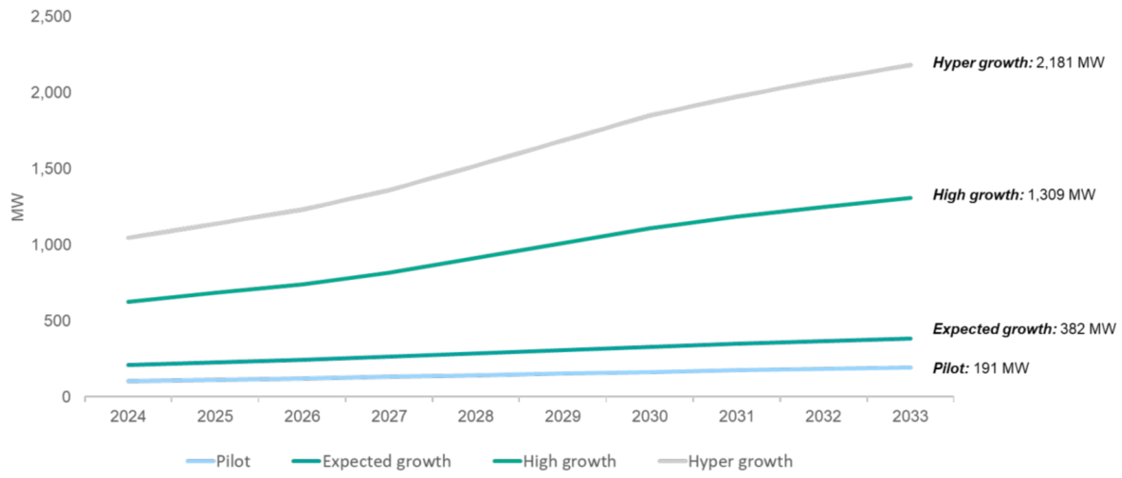

Figure 29: Forecast DPV capacity of the VPP based on different growth and participation scenarios[131]

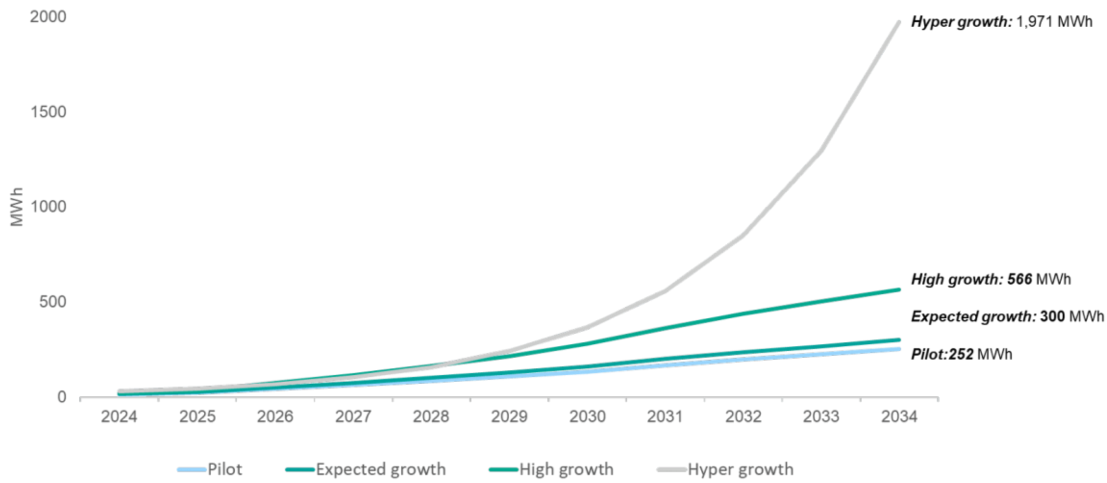

Figure 30: Forecast DESS capacity of the VPP based on different growth and participation scenarios

4.6 Overview of Models

Figure 31 shows an overview of the inputs required by Gridcog's platform to model cashflows and energy flows and how the platform's outputs and inputs relate to the DCF modelling.

[131] DER capacity is calculated based on the cumulative number of DPV and DESS added to the SWIS at the start of each year, per the ESOO 2023 growth forecasts, multiplied by the % VPP participation in each of the modelling scenarios.

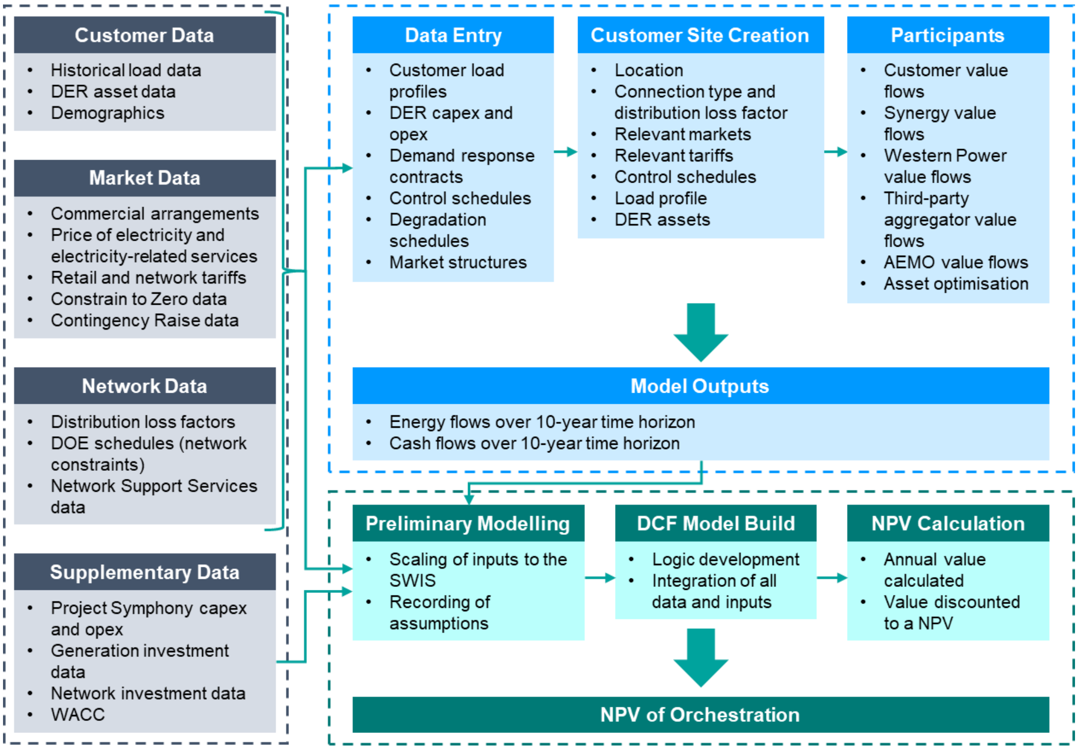

Figure 31: Inputs and relationship between models.

5. Results

The Pilot area for Project Symphony was selected based on the high penetration of DER in the area and some identified network constraints. Based on the total number of customers recruited to participate within the Pilot (989 DER assets and 514 aggregator and TPA customers), approximately 5% of the potential pool of DER assets that could have participated in the Pilot were recruited into the Pilot VPP. Whilst the level of customer participation provides a reasonable basis to demonstrate the technical capability of a VPP to respond to different scenarios examined within the Pilot, the actual value derived from the perspectives of the Pilot participants may be understated. That is, capturing the maximum value of DER aggregation is intrinsically linked to the number of customers participating within the VPP and increased participation in the VPP will be critical to success.

Whilst historical customer consumption and Pilot data have been used to extrapolate a value if DER orchestration is delivered at scale across the SWIS, there are some inherent limitations of the findings based on this approach given the Pilot area, participants and mix of DER assets are not representative of all demographics within the SWIS.

A further refinement of the modelling completed within the CBA and analysis of alternative commercial arrangements between DER customers, the aggregator and TPA (discussed in sections 5.1.8 and 6.1) would be beneficial to understand how the value of DER orchestration can be improved and passed through to customers. Whilst some of this analysis can be undertaken by changing variables within the CBA model, deeper insights would be delivered through whole of system modelling to consider the onflow of benefits to whole of system energy costs that have not been addressed within the scope of the Pilot and CBA.

5.1 CBA Results

The CBA found that there was an overall net benefit in the Bi-directional Balancing Market and Fully Orchestrated test scenarios under all modelling scenarios over the 10-year modelling period. When considered in isolation of each other, the NSS, CTZ and ESS-CRR test scenarios did not result in a net positive NPV. The negative NPV is attributed to the revenues received from the aggregator and TPAs being less than the associated cost of providing this service. Altering the payment arrangements could have a positive impact to the NPV of the aggregator, in addition to increasing the participation of DER (e.g., DESS and controllable loads that can provide NSS and ESS-CRR services). It is, however, noted that in doing so, this will lead to an increase in value of NSS, CTZ and ESS-CRR payments, subsequently increasing the costs for Western Power and AEMO, which ultimately increases the cost passed on to market participants.

The sections that follow provide an overview of the energy flows (imports and exports) under each modelling and test scenario, followed by the CBA results for each of the four test scenarios and the Fully Orchestrated option.

5.1.1 Energy Imports and Exports

An identified value stream of DSER orchestration is enabling VPP participants to optimise the return on their DER investments by enabling access to energy arbitrage opportunities. To maximise access to energy arbitrage opportunities that are modelled in the test scenarios, the energy exported by customer DPV is not used to self-serve the operational demand of residential customers but is instead used to reduce Synergy's need to purchase wholesale energy from the market. That is, the volume of energy required to be purchased from the market is reduced in proportion to the volume of DPV exports in the VPP. The energy exports are traded directly back into the market to be used by other market participants, however as this relationship sits outside the boundary of the CBA it is not considered in the modelling. An overview of this flow of energy between the VPP participants, the aggregator and the market is illustrated in Figure 32.

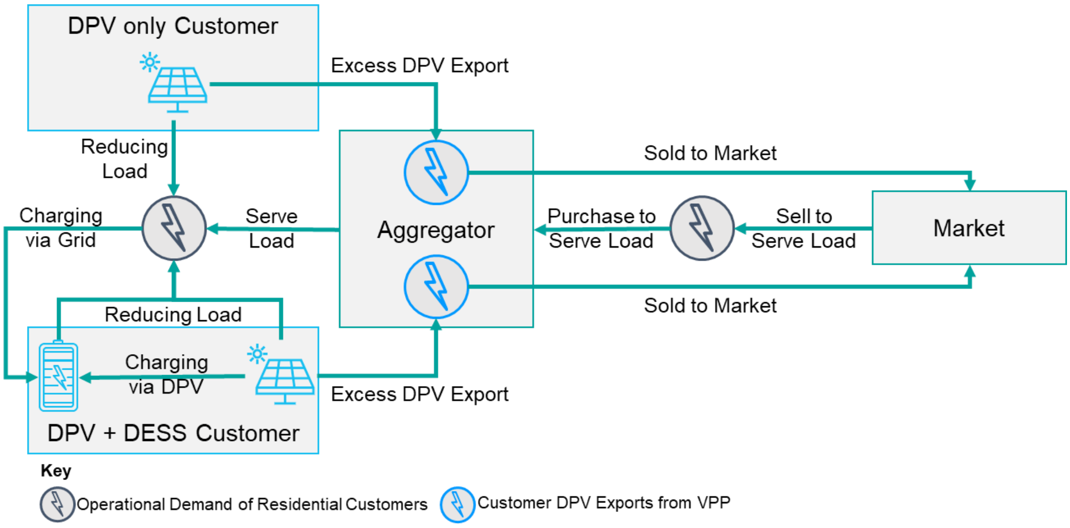

Figure 32: Overview of modelling of energy flows

Based on the above illustration, when solar is curtailed the aggregated DPV energy exports are reduced, resulting in a decrease in the overall supply of energy from the aggregated facility. As the wholesale market balances supply with demand, the decrease in supply from the aggregated facility must be met with an increase in supply from generators in the market, or in some circumstances a reduction in demand. As the cost and revenue of generation and the wholesale market was not considered in the CBA, the balancing of the wholesale market is not reflected in the modelling and as such, the energy flows modelled in the CBA between Synergy as the aggregator and the market do not reflect any increase (or decrease) in generation required by the market to balance supply and demand. That is, the CBA only evaluated the cashflow between VPP participants in the four test scenarios, omitting cash and energy flows related to generation and the wholesale market.

The Bi-directional Balancing Market and Fully Orchestrated test scenario were the only scenarios under which energy arbitrage opportunities were pursued by the aggregator, which is represented as revenue received from trade in the wholesale market. In the base case and NSS, CTZ and ESS-CRR test scenarios, the aggregator does not have the capability to pursue energy arbitrage opportunities and as such does not receive revenue from selling customer DPV exports to the market. Given that the net energy purchased under the wholesale market by Synergy, which takes into account Synergy's total demand (residential and commercial customers) and its centralised supply (generators owned by Synergy), was not considered in the modelling, the inability to trade DPV exports in the market was identified as an opportunity cost, whereby it was represented as a negative cashflow. That is, the cost is reflected as a cost to Synergy to effectively pay a third party to take the excess DPV energy that has been exported by the VPP. Due to this, curtailment of exports did not impact the volume of imports from customers, nor the volume of energy the aggregator was required to purchase from the market.

Over the modelling period, energy imports by customers across the SWIS, which includes both DPV and battery owners and customers that do not own DER, will continue to increase year-on-year in line with an expected increase in energy demand, as shown in Figure 33.

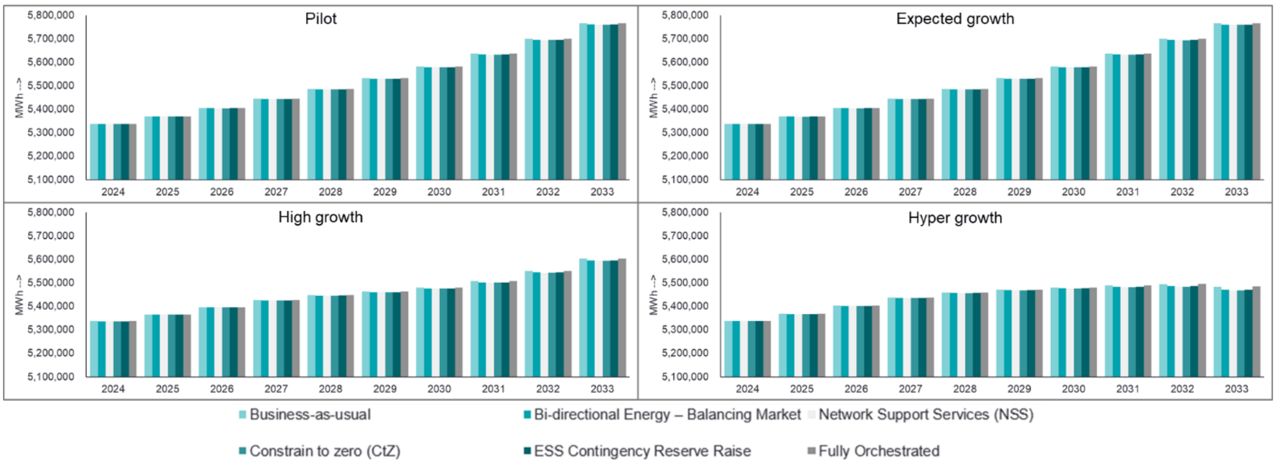

Figure 33: Energy import by customers (MWh)

There is a slight reduction in the volume of energy imported by customers from the WEM in all test scenarios, except the Fully Orchestrated test scenario, when compared to the base case. This slight reduction is specifically tied to customers owning a DESS that participate in the VPP, with DPV only customers maintaining the similar levels of imports as the base case across all test scenarios, as shown in Figure 34:

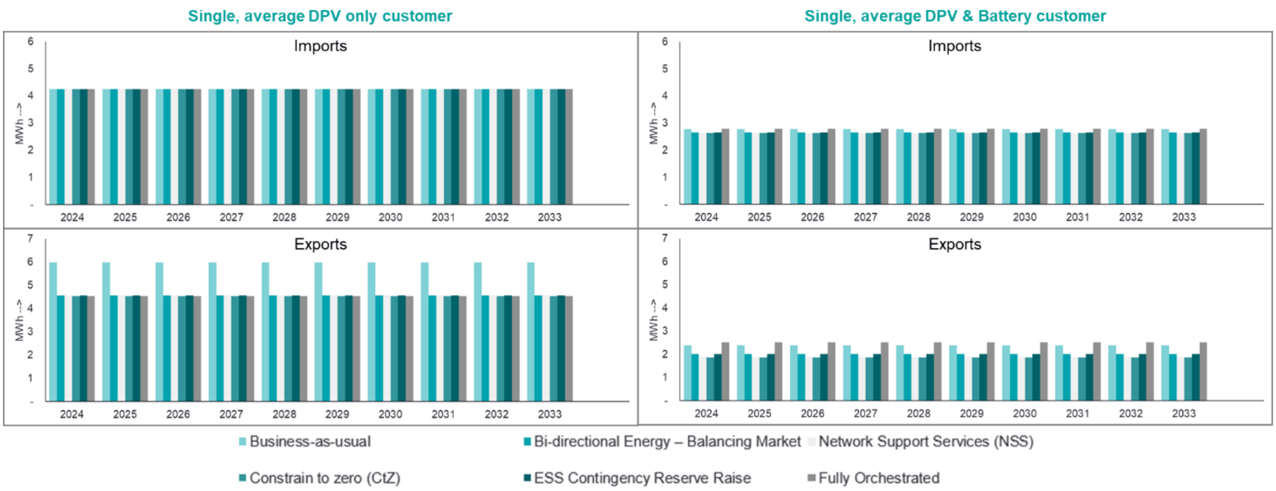

Figure 34: Energy imports and exports for DPV only customer and DPV and battery customer (MWh)

The minor reduction in imports for DESS owners is attributed to customers being optimised to minimise the retail tariff, with orchestration controlling batteries to maximise their charge via solar generation and minimise energy required to be imported from the grid. DESS owners experiencing an increase in energy imports under the Fully Orchestrated test scenario can be attributed to the increased activity of batteries from orchestrating them to provide multiple services (Balancing Market, NSS, ESS-CRR), increasing their overall charging and discharging time. However, as customers are still optimised to minimise the retail tariff cost, DESS owners also experience retail tariff savings due to the VPP controlling batteries to maximise imports during off-peak and super off-peak periods, during which a lower tariff value is applied. As such, as energy demand increases, the retail tariff paid by customers to Synergy is also expected to increase, although the forecast growth in DPV paired with a battery will abate the growth in revenue to an extent.

The total volume of energy exported to the grid by DPV and DESS owners in the base case is higher compared to all the other DER orchestration test scenarios. In the *Pilot* modelling scenario, energy exports in the base case increase on average by 6.62% per year. By way of comparison, in the Bi-directional Balancing

Market test scenario, exports increase on average by 5.63% each year and are consistently lower compared to the base case for all test and modelling scenarios. This is shown in Figure 35:

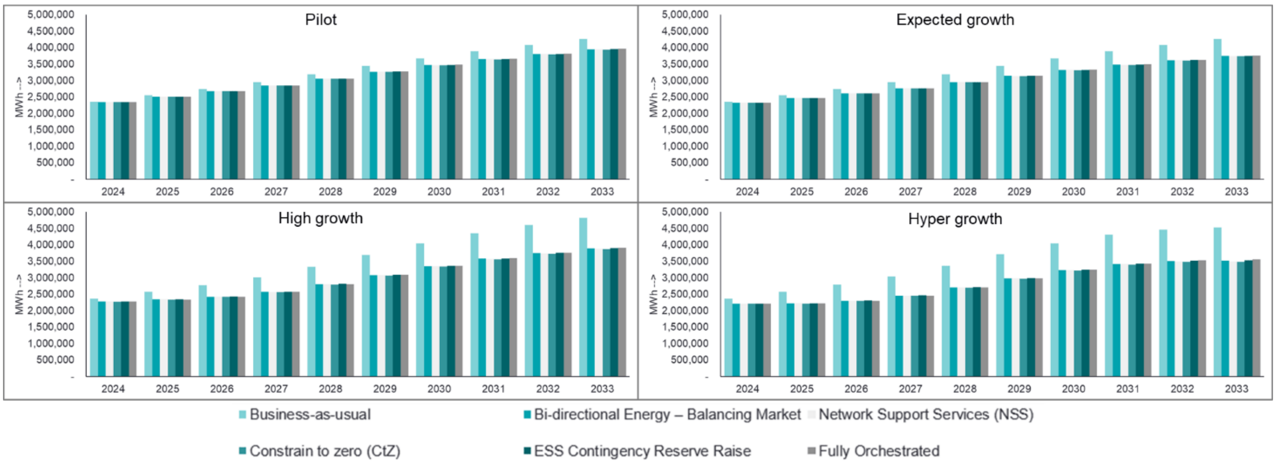

Figure 35: Energy exports by customers (MWh)

A breakdown of the year-on-year comparisons of exports under each test and modelling scenario compared to the base case is provided in sections 5.1.3 to 5.1.7. The higher exports in the base case compared to the orchestration scenarios can be attributed to the static 5kW export limit applied for single phase connections, as per Western Power's Basic Embedded Generator Connection Technical Requirements,[132] and absence of DOEs, discussed further in section 5.1.8.

In the Bi-directional Balancing Market and Fully Orchestrated test scenarios, there is a reduction in value of wholesale energy purchased by Synergy to meet energy demand in all modelling scenarios, when compared to the value of wholesale energy purchased by Synergy in the base case, as shown in Figure 36Figure 39Figure 36.

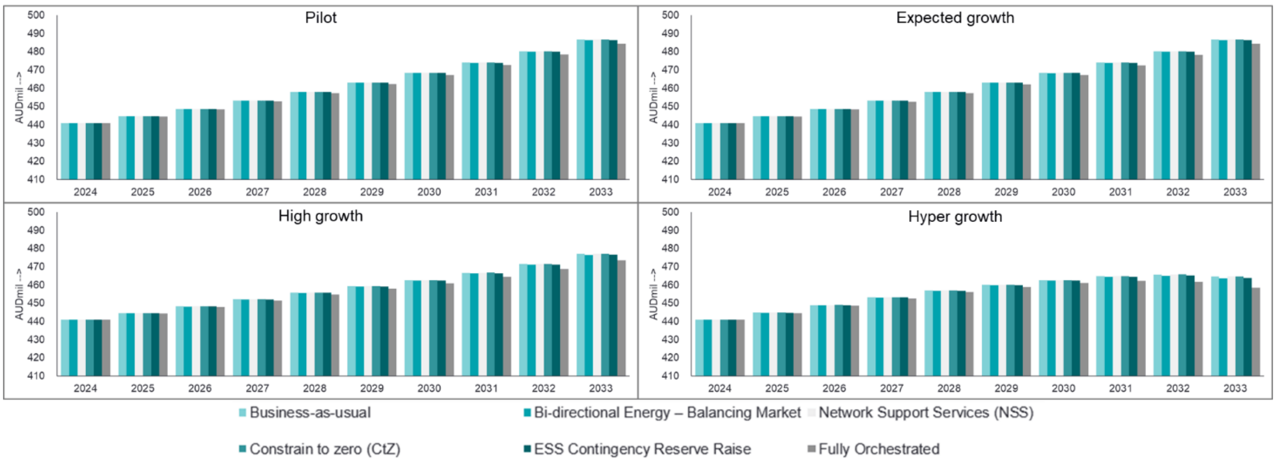

Figure 36: Energy purchased by the Aggregator from the WEM balancing market (AUD mil)

This decrease, though consistent with the reduction in energy imports of battery owners illustrated in**Error! Reference source not found.** Figure 34, is more aligned to the impact of using distributed batteries to take advantage of energy arbitrage opportunities, with the minimal cost savings shown reflecting the value of

[132] Western Power, 2023. *Basic Embedded Generator (EG) Connection Technical Requirements*

energy arbitrage opportunities in the WEM. As VPP participation of the number of customers owning a battery increases, the value of cost savings related to wholesale energy purchasing will continue to increase, compared to the base case, as demonstrated in the *High growth* and *Hyper growth* modelling scenarios.

Figure 37 Figure 37 shows the revenue earned by the aggregator through the sale of DER exports into the balancing market in the Bi-directional Balancing Market and Fully Orchestrated test scenarios.

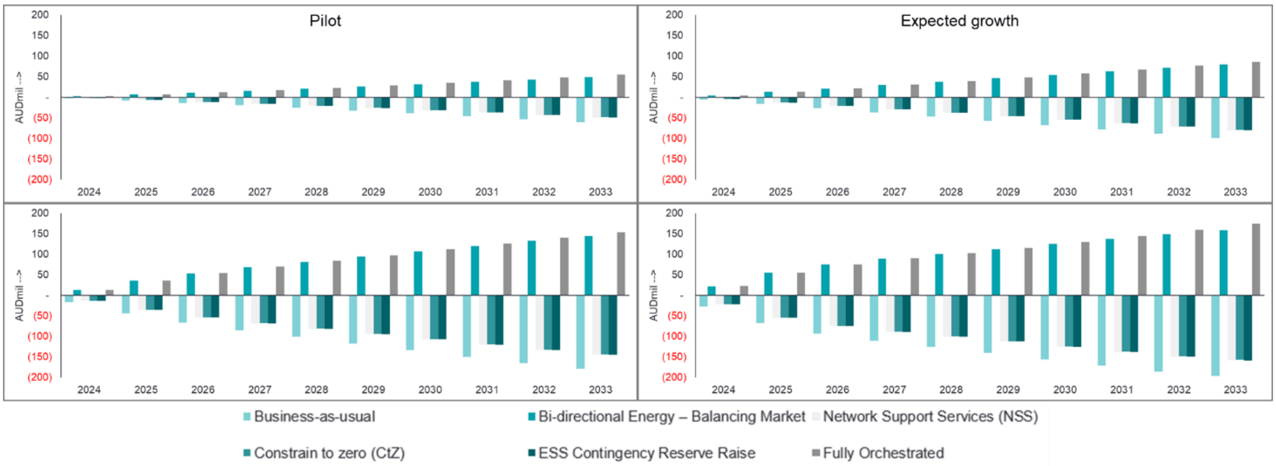

Figure 37: DER energy sold by Synergy to the WEM balancing market - Pilot modelling scenario

Under the base case, NSS, CTZ and ESS-CRR test scenarios, however, an opportunity cost is incurred to manage DPV generation pushing the balancing price down, reflecting the aggregator not having the capability to do so under these test scenarios. As such, the Bi-directional Balancing Market and Fully Orchestrated test scenarios also reflect the overall increase in energy trade in the WEM as a result of orchestration.

The results of the DCF analysis are provided in the sections below.

5.1.2 Base Case

The base case test scenario provides a counterfactual unorchestrated DER scenario, where DPV and DESS adoption continues to grow in line with the forecasts set out in the ESOO but are not 'orchestrated' within a VPP. The base case test scenario assumes that the WEM reforms that will come into effect in October 2023 will be implemented regardless of the outcome of Project Symphony. As such, under the base case test scenario, the TPAs' role does not exist, nor does a VPP exist, so customer DER are not enabled to participate in the WEM and are not used to provide market services and NSS, and the Constrain to Zero service is not included. It is acknowledged that TPAs currently offer off-market products, however these have not been considered in the base case. Planned network investments on the Western Power network, provided in the 10-year business plan and 2025 Network Plan, are included to reflect that investment will be required to manage network constraints in the absence of DER orchestration.

To provide a reasonable representation of how DER assets would be expected to respond to the different test and modelling scenarios when scaled across the SWIS, de-identified consumption and export data was obtained from Synergy for the customers participating in the Pilot between April 2022 to June 2023 and used in the modelling.

The customer data shows the seasonal changes in the import and export of energy over the year. This change in DER and customer consumption behaviour is provided in Figure 38 for a randomly selected DPV customer over three consecutive days in each of the four seasons. In each profile, consumption from the grid is minimised when gross solar generation is occurring and is sufficient to meet the customer's demand for energy and in each case, they have unconstrained export of excess solar generation during the middle of the day.

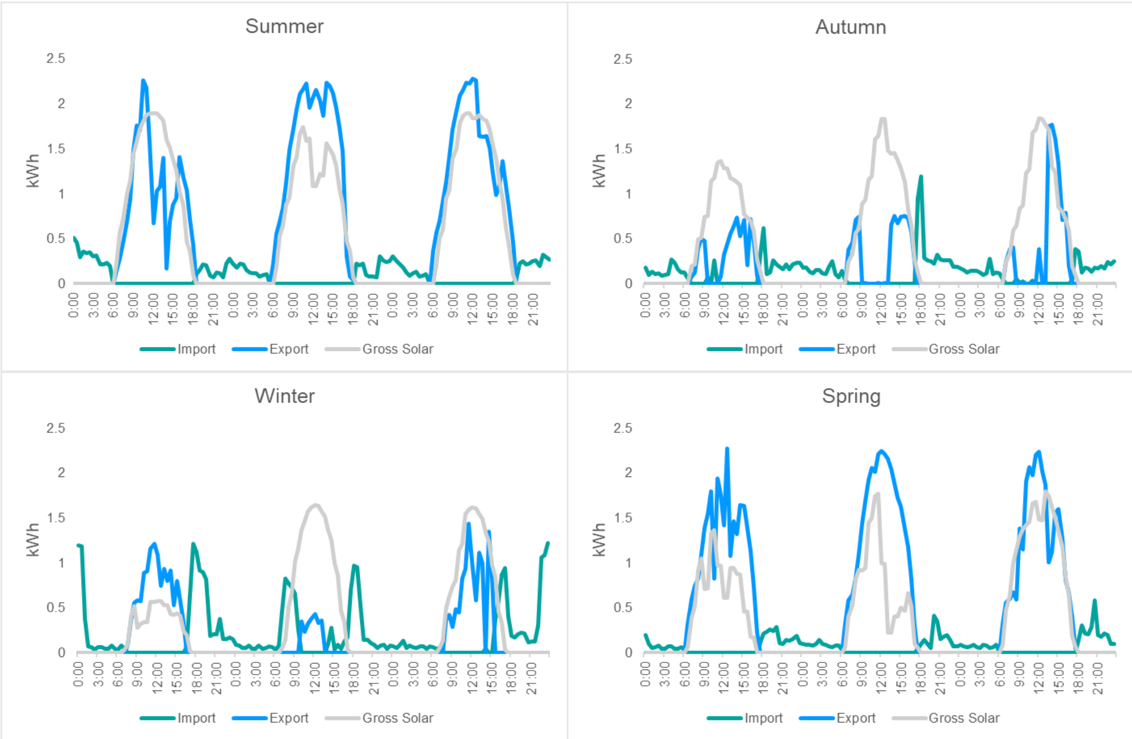

Figure 38: DPV only customer import and export profile base case test scenario

The profile of another randomly selected DPV and battery customer is provided in Figure 39Figure 39, illustrating how the customer can significantly reduce energy imported from the grid by maximising self-consumption and charging the DESS from gross solar generation during the day time, maintaining a steady state of charge, and then discharges in the evening when solar generation stops.

Figure 39: DPV and DESS customer import and export profile base case test scenario

The forecast undiscounted yearly cashflows over 10 years in the base case for the *Expected growth* modelling scenario is provided in Figure 40. The descriptions of each cost and revenue category represented in the cashflows are provided in section 4.3.4. In the absence of a VPP in the base case, there are no requirements for a TPA, and as such there are no forecasted costs associated with the TPA in the base case.

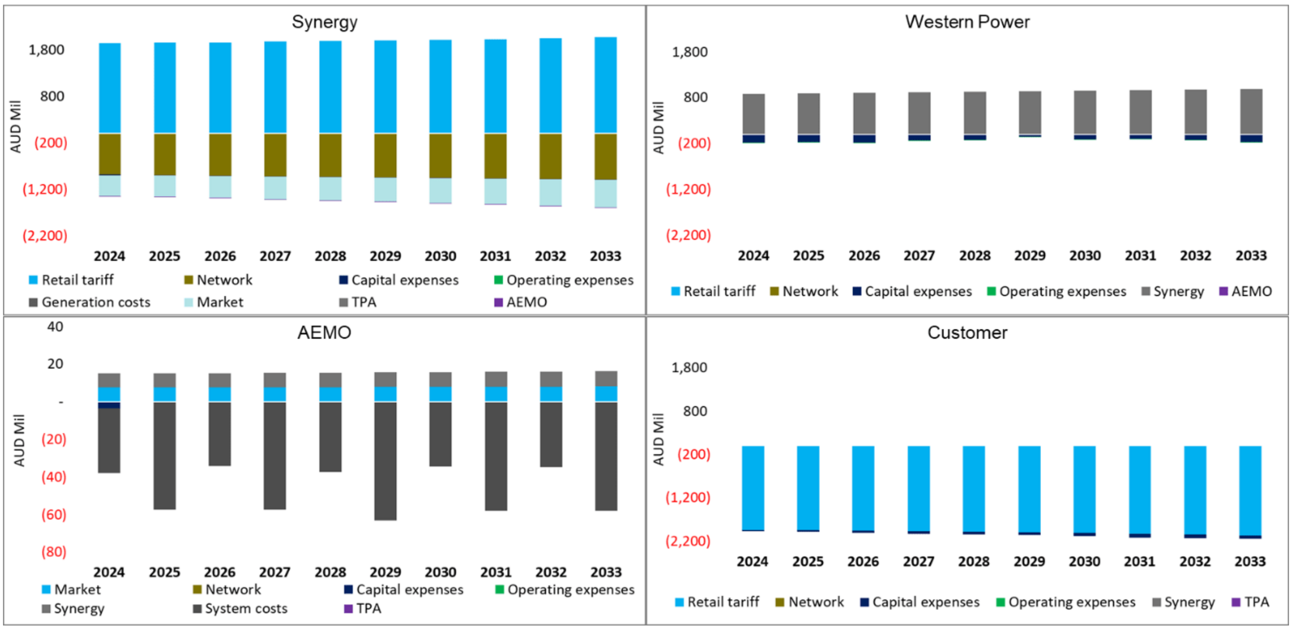

Figure 40: Base case undiscounted yearly cashflows in the base case test scenario (Expected growth)[133]

Western Power's main source of revenue is received from the network tariff charged to Synergy for energy imported from the grid, and this conversely is a cost for Synergy. An additional cost for Synergy that is reflected in the base case is the cost of purchasing energy from the wholesale market to supply its customers. Whilst Synergy often generates more energy than it needs to supply its customers through its generation business, it is also registered as an energy retailer and can purchase energy from other market participants.[134] During periods of high solar output, usually coinciding with low levels of demand, the balancing price of energy will decrease and can result in negative pricing for registered generators. This exposes generation businesses to a potential loss, whereby they must pay the market to take the excess energy, incur the cost of either continuing to generate without receiving revenue from trading in the wholesale market and the cost of switching their generators off and then on again, or invest in energy storage solutions or demand response programs (e.g., flexible loads). As DPV continues to grow, traditional centralised generators in the market will be exposed to increased risk and volatility.

The risk of unmanaged DPV also has implications for the market operator, whereby the costs of LFAS regulation and MDS, procured under the NCESS framework, incurred by AEMO will continue to increase as the number and capacity of DPV connected to the SWIS increases. The cost of procuring the LFAS regulation and MDS by AEMO is considered within the cashflow analysis, however the cashflows are not offset by a recovery of costs from market participants, other than the market and registration fees received from Synergy, nor does it consider revenue received from other market participants and large contestable customers, and other energy markets, such as the RCM and STEM, that are outside the scope of the CBA. As such, the LFAS and the MDS are reported as a cost in the base case and following test scenarios.

The base case cost incurred by customers reflects the purchase of energy from Synergy using the A1 tariff for customers, or the Midday saver tariff for customers with DESS, less any revenue received from the solar feed-in tariff (REBS or DEBS). In the absence of a VPP and market for DER orchestration, customers cannot access the WEM to generate additional revenue.

The major capital expenses forecast by Western Power relate to network investments in both the transmission and distribution networks, where zone substations and distribution feeders are reported to be above or approaching their POE10 and POE50 design limits, respectively, and will require augmentation within the next 10 years to account for existing network constraints but also allow for future growth.

The cost of purchasing DER assets by customers is captured in the base case, however the costs of these purchases are not subsidised. Although there is no VPP under the base case, the modelling assumes that customers will continue to invest in DPV and DESS at the projected growth rates forecasted in the 2023 WEM ESOO.

5.1.3 Bi-Directional Energy – Balancing Market

The WEM Balancing Market (or real-time market) is a 'gross pool' market for dispatch and 'net pool' for settlement that determines the most economically efficient dispatch of generation to meet system electricity demand at a given time. Under this scenario, registered facilities, including DER aggregated generation facilities, via an aggregator, can offer (sell) or bid (buy) energy into the Balancing Market whilst incorporating or adhering to a DOE, published by the DSO.

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[133] Note: Cashflows for AEMO are shown on a different scale compared to the other participants due to the large difference in size of cashflows between them.
[134] As Synergy's generation business falls outside the scope of this CBA, the full retail energy supply required to meet customer demand has been reflected as energy purchased from other market participants.

The Bi-directional Balancing Market provides a mechanism to manage the stability and reliability of the system to match supply and demand and respond to sudden changes in weather or unexpected external events in real time, using simulated forecast prices based of the WEM balancing price to incentivise market participants to respond to system imbalances by encouraging an increase in generation or reduction in demand, whilst optimising the amount of renewable hosting capacity on the network by publishing the total available power transfer capacity (load and generation) at a given time.

The energy profile over three consecutive days of a randomly selected customer is provided in Figure 41Figure 41. In summer and spring, solar exports are curtailed due to DOEs and responses to price signals between 11am and 3pm.

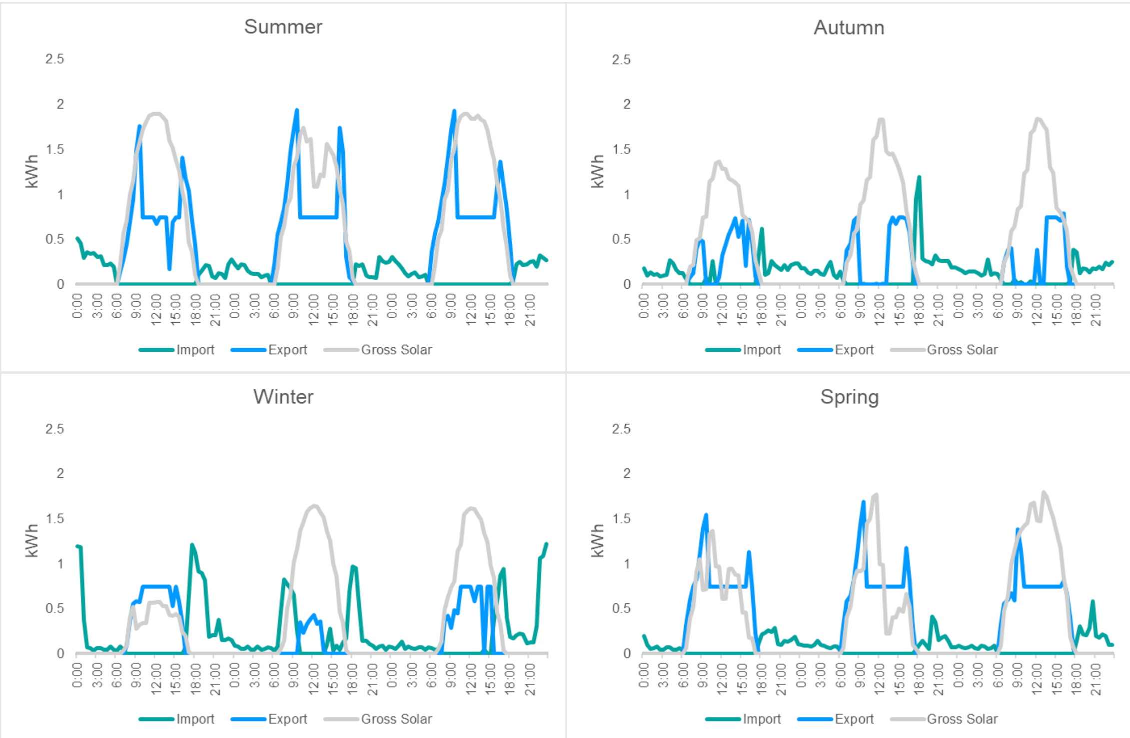

Figure 41: DPV only customer import and export profile Bi-directional Balancing Market scenario

Under the Bi-directional Balancing Market scenario, the DESS is configured to charge when the balancing price is negative or low, which may coincide with periods where solar exports may be constrained, as shown in Figure 42Figure 42.

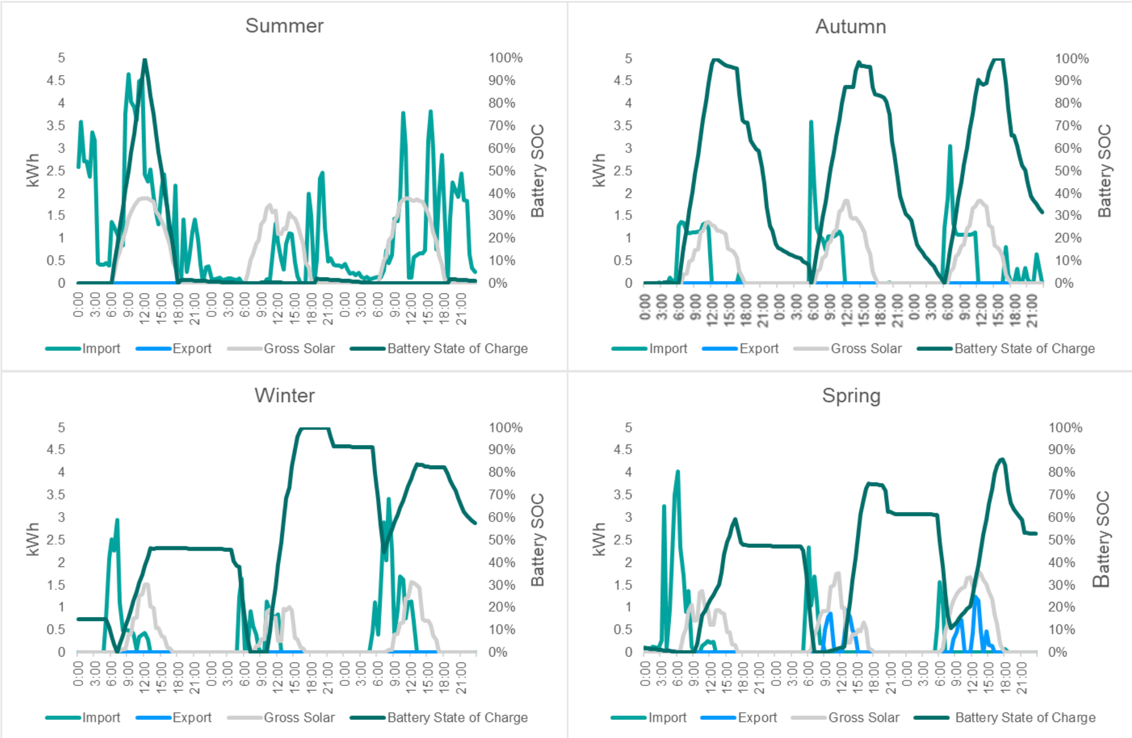

Figure 42: DPV and DESS customer import and export profile Bi-directional Balancing Market scenario

Under the Bi-directional Balancing Market scenario, the volume of energy exports reduces compared to the base case, in response to DOEs and price signals. This change becomes more pronounced throughout the modelling period as the number of DPVs and number of VPP participants increase. As a result, the feed-in-tariff paid to customers for solar exports decreases in relative proportion to the reduction in exports. As exports decrease and customers consume or store energy that would otherwise be exported to the grid, energy imports are also observed to be slightly lower when compared to the base case, though only marginally. As discussed in section 5.1.1, this minor reduction in imports can be attributed to battery owners, with customers who own DPV only experiencing the same level of imports as the base case. As mentioned, this is expected to be a result of VPP optimisation configurations that seek to minimise customers' retail tariff costs. Additionally, the Bi-directional Balancing Market and Fully Orchestrated test scenarios co-optimised orchestration for the aggregator to minimise network tariff costs and minimise exposure to higher energy prices when purchasing energy from the market, with each of these given equal weighting in priority to the goal of minimising customers' retail tariff costs. As both the retail tariff for the customer and the network tariff for the aggregator are calculated based on total energy imported, measured at the meter, they both seek to minimise imports wherever possible, maximising the use of DPV generation by seeking to charge batteries during times of high solar output and low demand. The optimisation seeking to minimise the aggregator's exposure to high energy prices when purchasing energy from the wholesale energy market complements these by seeking to charge batteries during low pricing, which normally corresponds with the off-peak and super off-peak periods used by the Mid-Day Saver tariff. It should however be noted that the total volume of energy consumption increases each year in keeping with the forecast increase in demand for energy.

A summary of the average change over 10 years for each of the modelling scenarios, compared to the base case is provided in Table 21.

	Difference to base case over 10 years (%)			
	Pilot	**Expected**	**High**	**Hyper**
Energy imports (MWh)	▼0.04%	▼0.04%	▼0.06%	▼0.07%
Energy exports (MWh)	▼4.55%	▼8.3%	▼17.32%	▼22.33%
Feed-in tariff paid to customer	▼4.12%	▼7.49%	▼15.5%	▼22.73%
Retail Tariff Revenue	▼0.02%	▼0.02%	▼0.02%	▼0.03%
Network Tariff Revenue	▼0.02%	▼0.02%	▼0.03%	▼0.04%
Energy purchased by Synergy from the WEM balancing market ($)	▼0.03%	▼0.03%	▼0.05%	▼0.06%
DER energy sold by Synergy to the WEM balancing market ($)	▲223.82%	▲224.07%	▲224.25%	▲224.3%

Table 21: Impact of Bi-directional Balancing Market changes compared to the base case

Through the Balancing Market, customers can access the WEM via an aggregated facility, providing them with the opportunity to improve the DER return on investment. As mentioned, the reduction in customer imports is minimal and only experienced by battery owners, who also receive the benefit of shifting battery charging to off-peak and super off-peak periods with lower pricing, resulting in little difference in the retail tariff charged to customers by Synergy. Rather, the increased curtailment of customer DPV and corresponding reduction in payment received via feed-in tariffs result in customer bills increasing. Across customers participating in the VPP, Synergy experiences a net increase in retail revenue from customers with a NPV of $28 million in the *Pilot* modelling scenario over 10 years compared to the base case, which increases to a NPV of $131 million in the *Hyper growth* modelling scenario. The increase in customer bills, however, is only experienced by customers without a DESS, with customers owning a DESS experiencing a minor decrease ($1 million in the *Pilot* modelling scenario to $2 million in the *Hyper growth* modelling scenario), reflecting the result of maximising the benefit of the time-of-use Mid-Day Saver tariff via orchestration. This builds on the economic assessment conducted as part of work package 2.1, which suggested DER orchestration as most economically valuable for customers with a DESS.

Additionally, benefits customers receive from orchestration are offset by an increase in costs relating to the installation of additional hardware to enable visibility and participation in the VPP. The cost of enabling hardware during the Pilot was incurred by the aggregator, however with the removal of subsidies to offset the cost of purchasing new DER and supporting hardware, the cost of communications devices is expected to be passed on to customers, except for data recording devices that are required by the aggregator and AEMO to verify the delivery and performance of market services. The impact of changing the cost allocation for DER orchestration hardware (e.g., communication and recording devices) is discussed further in section 6.4.

The combined NPV, which includes the net cashflows of all stakeholders, is positive across all four of the modelling scenarios as shown in Figure 43 and Table 22. This outcome however is nuanced in how the costs and benefits of DER orchestration are distributed across the participants, which is discussed further in section 5.1.8.

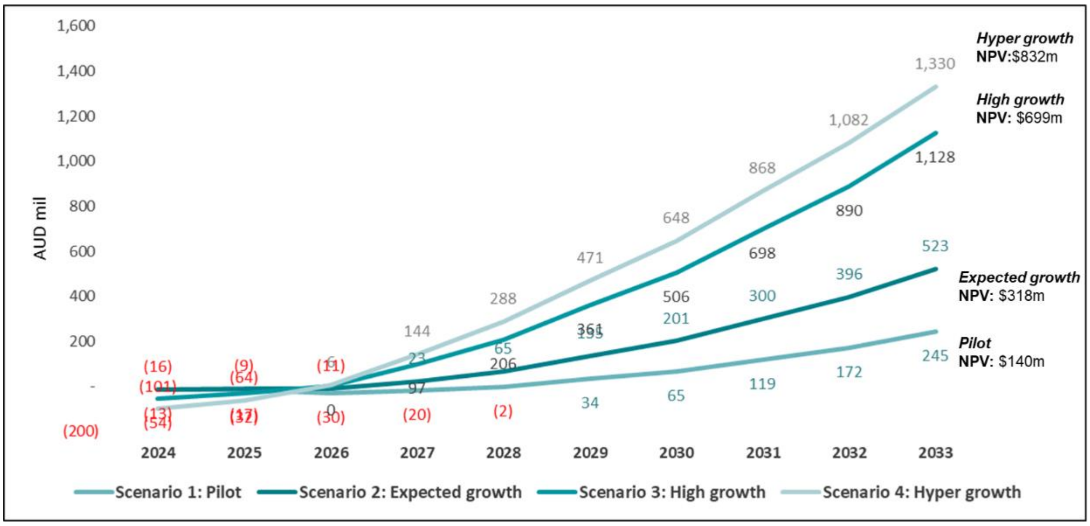

Figure 43: Combined undiscounted cashflow Bi-directional Balancing Market scenario

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$123	-$211	-$433	-$529
Western Power	-$54	-$54	-$54	-$55
AEMO	$131	$223	367	$378
Customer	$270	$493	$1,079	$1,352
TPA	-$85	-$134	-$260	-$314
Combined net NPV (AUD mil)	$140	$318	$699	$832

Table 22: Combined NPV for Bi-directional Balancing Market scenario (AUD mil)

When DER is orchestrated solely for use in wholesale electricity trade, the modelling shows that Synergy experiences a negative NPV. This is to be expected, as Synergy bears the full operating expense of hosting the Aggregator Platform and cost of recruiting customers into the VPP, whilst only tapping into one source of value, the Balancing Market. The largest driver for this, however, are the payments made to customers for participating in the VPP. Under the *Expected growth* modelling scenario, Synergy receives an additional $76 million from increased customer bills, however, this is dwarfed by the $1.14 billion over the 10-year period for customer incentive and orchestration payments. As such, it is evident that the commercial arrangements made during Project Symphony's Pilot are not reflective of value generated for Synergy, nor any reduction in value experienced by customers.

The current arrangements for customer incentive payments (included under operating expenses in Figure 44) used in the Pilot result in a decrease in NPV of $211 million under the *Expected growth* modelling scenario for Synergy, compared to the base case test scenario, with the incremental yearly undiscounted cashflows shown below.

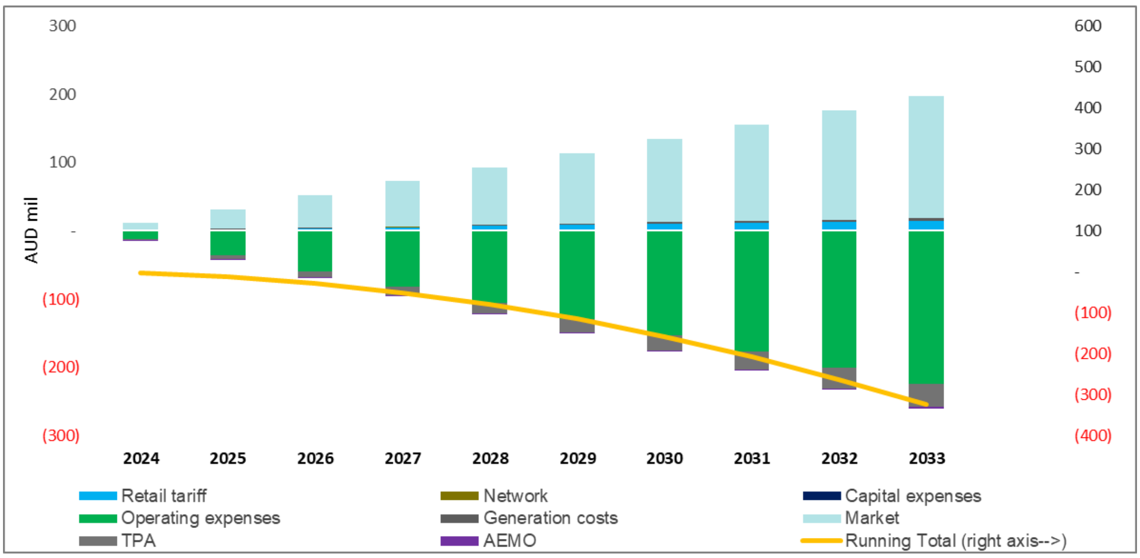

Figure 44: Incremental undiscounted cashflows for Synergy in the Bi-directional Energy Balancing Market scenario (Expected growth)

Though studies in the NEM have shown significant value arising from using DER to trade in wholesale electricity, this is due to the high energy arbitrage opportunities present caused by high price volatility in the market. Comparatively, the WEM experiences stable prices due to a single market clearing price, where energy price limits are lower compared to the NEM, which results in facilities recovering most of their capital expenditure through the RCM. This leads to significantly less energy arbitrage opportunities and as such, Synergy cannot rely on energy arbitrage to provide significant value in the Balancing Market, suggesting that DER orchestration for use in wholesale energy trade alone does not provide sufficient incentive for investment. It is noted that the minimum price cap (also referred to as the floor price or minimum STEM price) in the WEM's balancing market is -$1000 per MWh,[135] which is the same as the NEM. The minimum STEM price was reviewed by the Economic Regulation Authority WA in 2022 and it was determined that the existing floor price was appropriate when analysed against the review criteria the WEM rules (clause 6.20.14).

Western Power shows no material change compared to the base case in terms of its revenue, with network tariffs remaining the main source of revenue. However, significant capital expenditure related to network augmentation are incurred across the 10-year period with limited opportunities to defer expenditure using the Balancing Market alone. This is largely attributed to the fact that parts of the network are already overloaded and will need to be augmented and energy demand is increasing at a higher rate than the year-on-year reduction of energy imported from the grid. Regarding the negative NPV shown for Western Power, it is important to note that current regulations provide cost recovery mechanisms for Western Power, allowing them to increase their network tariffs to account for increases in costs, whilst also enforcing decreases to tariffs when costs decrease. Though out-of-scope of the CBA, the impacts on these network tariffs would result in a flow-on effect, impacting the value orchestrating DER via a VPP generates for Synergy and end-user customers.

The NPV for AEMO is positive due to the avoidance in LFAS regulation costs. Load Following Ancillary Services (LFAS) are a type of ancillary services that is used to balance electricity generation and consumption in real-time. The forecast cost for LFAS is based on a regulatory requirement associated with unmanaged DPV capacity, where an increase in the total capacity of registered DPV connections, when left unmanaged will require a commensurate increase in LFAS costs of $650,000 per MW of additional DPV installed.[136] When DER is managed, peak LFAS is expected to reduce resulting in an avoided cost to AEMO. Like Western Power, cost recovery mechanisms are regulated to ensure AEMO breaks even, by passing these system costs on to market participants. Though not included in the modelling, these mechanisms would also impact the value of DER orchestration for other market participants, with the decrease in LFAS regulation costs in the system expected to result in a decrease in market costs they incur.

As previously discussed, AEMO has identified that high levels of unmanaged DPV exports coinciding with record levels of minimum operational demand is a material risk to the safe operation and stability of the power system. The power system threshold, referred to as the operational minimum demand threshold (MDT) for the SWIS, was recently revised from 500MW to 700MW, the minimum level of operational demand required by AEMO to operate the power system in a secure and reliable manner.

A Minimum Demand Service (MDS) is covered under the NCESS framework and enables AEMO to procure a service which cannot be provided within the existing market. To qualify for the provision of this service, the MDS must be available between 10am to 2pm with the ability to increase withdrawal or reduce injection and be a minimum size of 10MW. In the absence of a MDS, the alternatives available to AEMO and Western Power to manage MDT include the ESM function and curtailment of DPV at a feeder level, which is likely to result in unpopular outcomes for the community. If the Balancing Market is operating effectively, it is expected that this will mitigate future MDS costs from being required, or the use of blunt instruments such as

[135] Economic Regulation Authority, 2022c. *Minimum STEM price review 2022: Final determination report*
[136] Calculated as the average cost of the 2020 and 2023 capacity years.

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ESM. To mitigate the potential impact of a MDT event, AEMO undertook an NCESS procurement process for a MDS for up to two years, commencing in October 2023.[137]

As VPP participation in the SWIS increases each year across all modelling scenarios, the cost of LFAS and MDS will continue to decrease.

Customers are significant beneficiaries in the Bi-directional Balancing Market test scenario, which is a pattern repeating across all the DER orchestration test and modelling scenarios, with its positive NPV counteracting the negative NPV of other stakeholders. As mentioned above, a large source of this is due to the DER orchestration and incentive payments that customers receive from the aggregator and TPAs for participating in the VPP. The current financial arrangements provide a NPV benefit to customers over the 10-year period of $766 million under the *Expected growth* modelling scenario compared to the base case, with the incremental yearly undiscounted cashflows shown below:

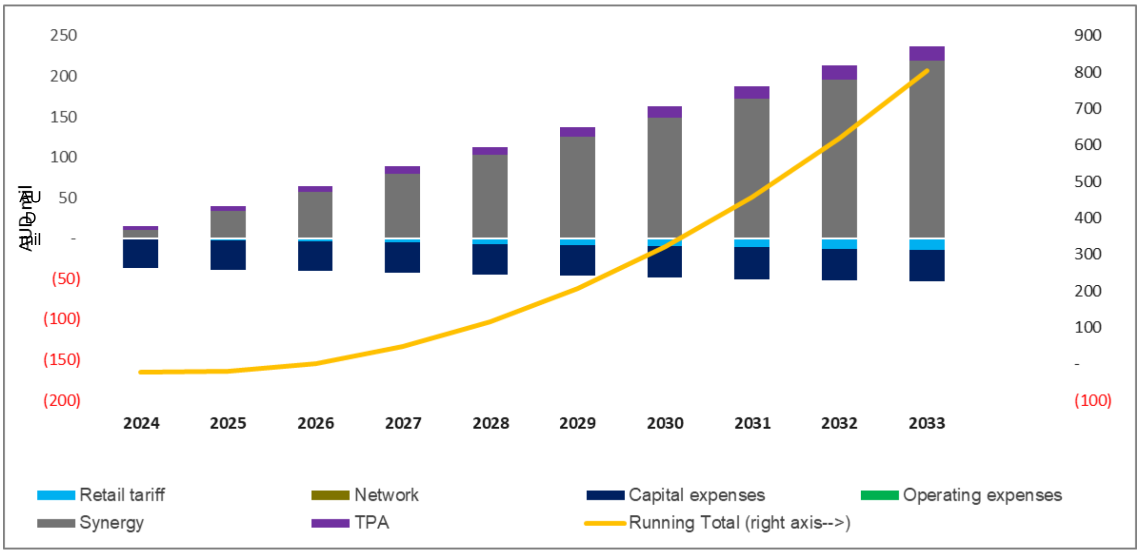

Figure 45: Incremental undiscounted cashflows for customers in the Bi-directional Energy Balancing Market scenario (Expected growth)

Like Synergy, the current commercial arrangements result in TPAs experiencing NPV loss of $134 million, with the payments TPAs receive from Synergy outweighed by the cost of payments made to customers, as well as the operating costs associated with their platforms, including integrating with the Aggregator Platform.

Whilst customers were shown to be a significant beneficiary of the commercial arrangements used in the Pilot, the approach used to incentivise and recruit customers to participate in the Pilot is not sustainable and do not reflect the commercial arrangements that will be used in future.

Alternate commercial arrangements and customer engagement models should be considered in the future, as this will have a significant impact on the distribution of value and costs to VPP participants. Suggested changes to the commercial arrangements used to recruit customers into the VPP are discussed in section 0. This includes recommendations to consider reducing customer incentive and orchestration payments to improve the value distributed to Synergy and TPAs. It also includes recommendations to consider alternative customer engagement models, such as a subscription model, where customers pay a subscription fee to the

[137] Energy Policy WA, 2023e. *Coordinator of Energy Determination: AEMO Non-co-optimised Essential System Service Trigger Submission*, “Minimum Demand Service”

aggregator for participating in the VPP and receive value as a result; or value-based payments, where a customer payment may be varied based on several factors, including type of DER enrolled in the VPP, location of the connection point (i.e. accounting for localised services such as NSS, resulting in a higher payment for DER in relevant locations), and the actual value generated by customer DER for services provided.

5.1.4 Network Support Services

NSS are a competing alternative to network augmentation and are a contracted service provided by a generator, retailer, or aggregator to the DSO to resolve network capacity shortfalls or degraded power quality at the least cost to consumers, through the provision of an active power response (load or generation). It includes two types of services, firm and flexible NSS, and can help to alleviate distribution level peak electricity demand or reverse power flow and/or local voltage issues that have been identified by the DSO. As a competing alternative, NSS is procured only when the cost is less than traditional augmentation such as larger transformers, more 'poles and wires', or otherwise expanding capacity. The firm NSS relates to a service whereby a NSS provider ensures a contracted volume of capacity is kept available for NSS requirements, awarding providers with a relatively high fixed availability payment and minor energy payment ($/MWh). In contrast, the flexible NSS is an ad-hoc service whereby providers respond to Western Power with current available capacity, resulting in no fixed availability payment awarded but a relatively high energy payment ($/MWh) used to compensate NSS providers.

NSS are procured on a contractual basis and need to be structured in such a way that they provide Western Power with the confidence that the services will be provided when required and delivers an equitable benefit to both Western Power, through the deferral of network augmentation, and the revenue earnt by the provider of the NSS (e.g., aggregators). Aggregators can elect to respond to a request for tender to provide NSS, by bidding a price that considers the cost of providing the NSS and the opportunity cost of any revenue that could be earned from other energy services. As such, the availability fee and energy payments paid to the NSS provider should be priced at a value that warrants the effort and investment required to recruit a sufficient volume and capacity of DER to provide the service and adequately compensates the DER owner for its ongoing use. For this CBA, only firm NSS were considered in the modelling as an alternative to network augmentation. To deliver a firm service and establish sufficient capacity to defer network investment, the Aggregator is required to enrol a sufficient amount of DESS or controllable load that can be made available when a NSS is called by the DSO, and enough spare capacity to mitigate the risk of various failure modes. A flexible NSS however provides the Aggregator with the option of whether to respond to a deployment signal. While this provides additional flexibility and choice for Aggregators and customers on how their DER is used, it provides some inherent limitations for the DSO when forecasting the amount of NSS capacity available when needed.

To support the testing of a firm NSS during the Pilot, the contract for the NSS included a fixed annual availability fee and a variable energy fee for each event, lasting 3 hours.

Under Western Power's regulatory framework, the cost of procuring NCESS, which include NSS, can be recovered via the 'D factor', where it can be demonstrated that the cost of NSS is lower than the cost of network augmentation.[138] The recovery of NSS costs was not considered in the scope of the CBA, however, it is noted that there are provisions in Western Power's Access Arrangement that enable Western Power to recover any loss of revenue, or disburse the value of deferred of capex (e.g. through reduced fixed or

[138] Economic Regulation Authority, 2022d. *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, "Attachment 10: Expenditure incentives and other adjustment mechanisms"

variable energy charges), effectively delivering an NPV of zero. As such, further analysis will be required to evaluate the impact on network tariffs when deploying NSS.

Is it broadly acknowledged that the NSS contract was structured in such a way to compensate the Aggregator to provide an NSS service during the Pilot, that would then support further evaluation of the value of this service. As such, the current NSS contract is not necessarily how NSS contracts may be structured in the future, particularly as augmentation costs vary depending on the location and characteristics of the local distribution network, and therefore the value that can be offered to aggregators is also variable. The commercial arrangements for NSS should be priced to incentivise the aggregator to provide NSS and also consider the opportunity cost of not being able to provide other energy services. It is further noted that Western Power has an established methodology to evaluate where NSS can be delivered as a competing alternative to network augmentation at a lower cost, which should be considered when determining the availability fee and variable energy fee paid per NSS event, so that there is mutual benefit for the aggregator, Western Power, and customer.

The expected number of NSS events per year was forecast using historical data from the Bureau of Meteorology, with an NSS event assumed to occur when the maximum temperature forecasted for that day was above 35°C and the minimum temperature forecasted for the day following was above 20°C.[139] As such, an average of 15 NSS events were assumed to occur annually between November and March, between 6pm to 9pm. To determine the value of deferred network feeder augmentation expenditure, it was assumed that that 50% of planned distribution feeder expenditure in the 10-year transmission plan where at or approaching their design utilisation limit and were candidates for NSS to mitigate anticipated annual load growth on the feeders. The remaining 50% of feeders were likely to require augmentation as they were already over utilised. Based on the capacity of DESS participating in VPP, the amount of load that could be displaced by NSS was then calculated to determine the cost of NSS and value of network augmentation deferral.

The provision of NSS will be dependent on the location of the DER connection point, to ensure that there is sufficient concentration of capacity of DESS or controllable loads in the areas of the network that have identified a localised network constraint, as opposed to having large volumes of DESS of controllable loads spread across the network[140]. To achieve the concentration of DESS or controllable loads required to provide NSS, targeted recruitment of these assets in specific areas will be required. To attract DESS and controllable DER load participation in these areas, higher incentive payments could be considered compared to other areas of the network that are unlikely to earn revenue from NSS. However, the value of targeting these areas is dependent on the commercial arrangements of NSS. Regardless, targeted recruitment of DESS and controllable loads will ensure access to other energy services that are not dependent on location (e.g., ESS-CRR). To support the aggregator to target recruitment of DESS and controllable loads in specific areas, the NCESS framework requires Western Power to publish a 10-year transmission network plan, which will support the identification of NCESS opportunities in the short to medium term.

As is the case with all the test scenarios, DPV enrolled within a VPP can receive DOEs which vary the limits placed on the amount of electricity the DPV system can export to the grid at any given time. The limits can change in response to various conditions, such as increasing or decreasing demand, network constraints or system stability. As shown in Figure 46, energy exports are curtailed when there is peak solar irradiance during the middle of the day.

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[139] Bureau of Meteorology, 2023 (accessed 2 August 2023).
[140] The modelling completed in the CBA only considered DESS. Controllable / interruptible loads were not included and should be considered in future trials.

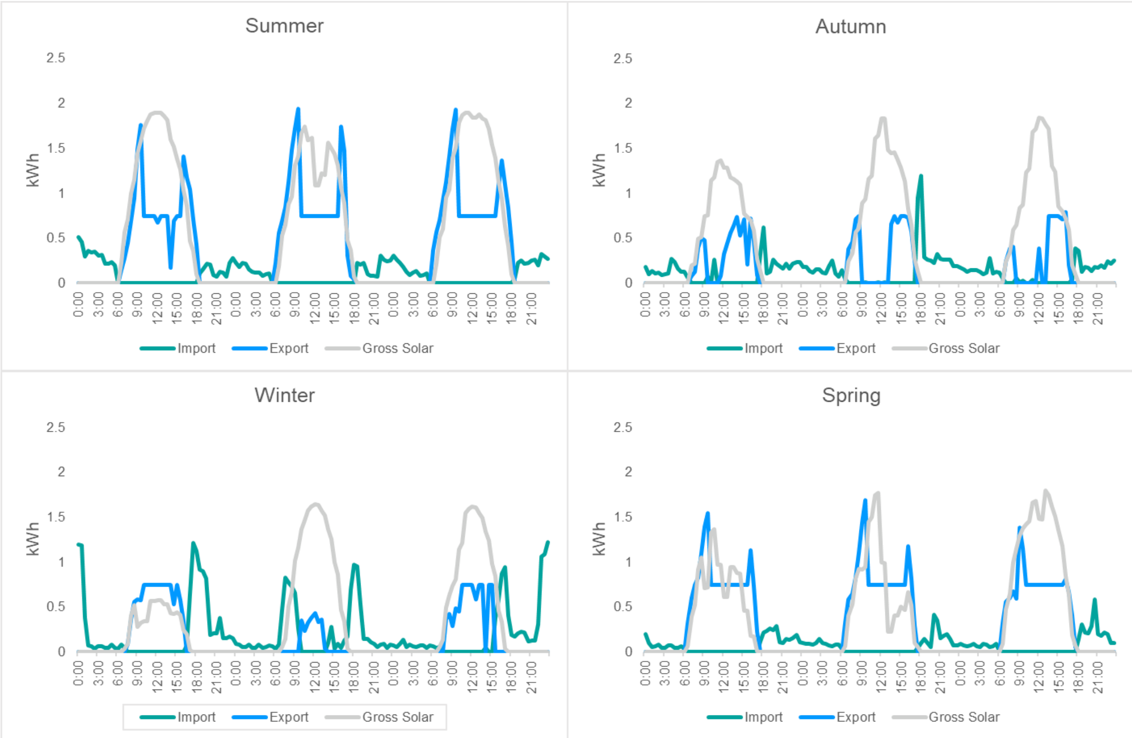

Figure 46: DPV only customer import and export profile NSS scenario

In the CBA model, NSS events are configured with two DESS control schedules that require the DESS to be fully charged by 6pm when provided with 24 hours of advanced notification of a NSS event, in the months of November, December, January, February, and March. Energy is discharged linearly over three hours during NSS events. The change in customer battery state of charge profile during a simulated NSS event in summer is shown in Figure 47.

Figure 47: DPV and DESS customer import and export profile NSS scenario

Based on information provided in the Network Plan 2025 and subsequent discussions with Western Power, it is understood that a significant number of zone substations and distribution feeders are already over utilised or approaching their utilisation limits and will require augmentation within the next 10 years.

Due to forecasting of distribution feeder augmentation requiring consideration of location-specific factors, as well as analysis of load-sharing opportunities, dynamic modelling required a whole-of-system approach which was outside the scope of the CBA. As such, the modelling considered a flat 2% load growth on distribution feeders. Additionally, 50% of feeders had already reached POE50 utilisation well above the 85% limit and been assessed by Western Power as not able to benefit from NSS, based on Western Power's Network Plan 2025. All other distribution feeders were identified as potential candidates for NSS in the CBA modelling, with the trigger for NSS being the POE50 limit of 85% utilisation, with 2% load growth applied each year. However, this may potentially result in less deferral of augmentation than NSS could be expected to provide, with some feeders experiencing load growth above the 2% per annum. As such, there is potential for orchestration of DER via a VPP to provide greater benefit through network augmentation deferral than what has been shown.

To determine the amount of NSS that could be provided by the VPP, and the fee paid to Synergy by Western Power for the provision of this service, the total energy capacity was calculated based on the number of DESS enrolled within the VPP in each year that could potentially offset an anticipated increase in loads on feeders that were approaching their utilisation limits. A noted limitation of this approach, and in the absence of detailed system and network modelling, is that for NSS to be effective, it must be deployed where there is a sufficient level of energy storage at a specific location to provide any tangible relief to localised network constraints at the locations. That is, the value NSS and of stored energy is most likely to be effective when there is sufficient VPP storage capacity connected to a specific feeder or substation.

Under the NSS scenario, there is negligible change to the energy imports, retail and tariff revenues and energy purchased from the WEM to meet residential demand. The observed changes relate to the reduction in energy exports and feed-in tariff paid to customers, which increases as the number of DPV added to the VPP increases year-on-year.

A summary of the average change over 10 years for each of the modelling scenarios, compared to the base case, is provided in Table 23.

	Difference to base case over 10 years (%)			
	Pilot	Expected growth	High growth	Hyper growth
Energy imports (MWh)	▼0.05%	▼0.05%	▼0.07%	▼0.09%
Energy exports (MWh)	▼4.62%	▼8.38%	▼17.44%	▼22.49%
Feed-in tariff paid to customer	▼4.06%	▼7.42%	▼15.5%	▼21.69%
Retail Revenue	▲0.06%	▲0.06%	▲0.09%	▲0.1%
Network Tariff Revenue	▼0.02%	▼0.03%	▼0.04%	▼0.04%
Energy purchased by Synergy from the WEM balancing market ($)	Min. change	Min. change	Min. change	Min. change
DER energy sold by Synergy to the WEM balancing market ($)	▼23.97%	▼24.16%	▼24.31%	▼24.36%

Table 23: Impact NSS changes compared to the base case

Similar to the Bi-directional Balancing Market test scenario, there is significant decrease in customer solar exports, providing a significant increase in customer bills ($61 million for all customers across the 10-year period under the *Expected growth* modelling scenario). However, this is offset by the same NPV value for customer incentives as the Bi-directional Balancing Market test scenario. The incremental yearly undiscounted cashflows generated for customers is shown below:

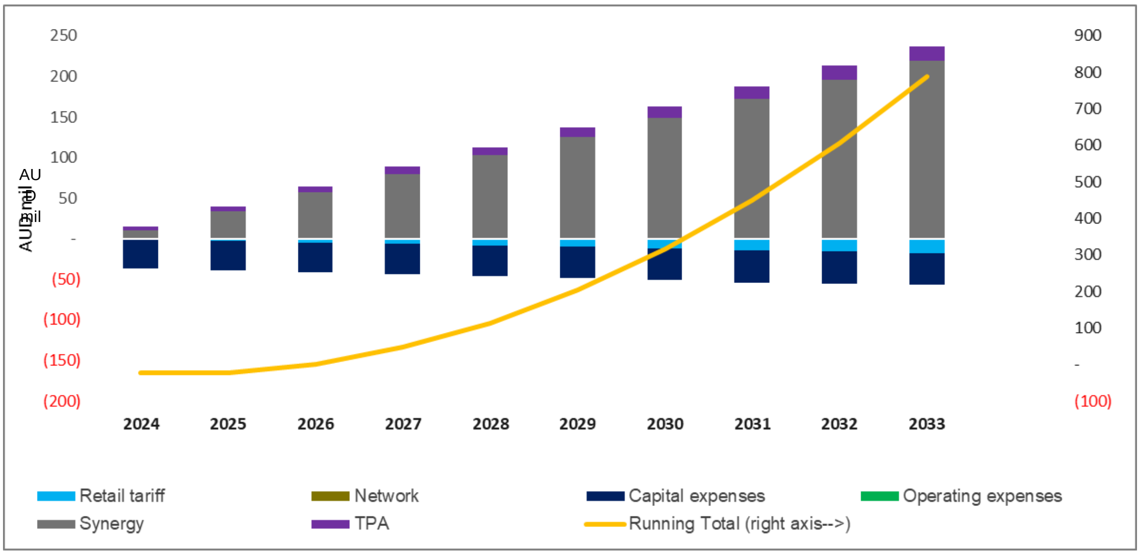

Figure 48: Incremental undiscounted cashflows for customers in the NSS scenario (Expected growth)

As shown, the value generated for customers does not significantly change compared to the Bi-directional Balancing Market test scenario, reinforcing the main source of value deriving from the customer incentive payments customers receive from Synergy.

In contrast, however, as the NSS test scenario does not include the capability of the aggregator to engage in wholesale energy trade, customer exports do not provide an additional benefit. Rather, the excess energy is treated as a cost for Synergy, who needs to pay to have it taken by another market participant. In this sense, the decrease in exports provides Synergy with dual cost savings: the first from lower feed-in tariff payments and the second from reduced excess energy needing to be managed, as shown in Table 23. Figure 49 shows the incremental yearly undiscounted combined cashflows, which demonstrates NSS as a standalone service is an insufficient investment signal for orchestration:

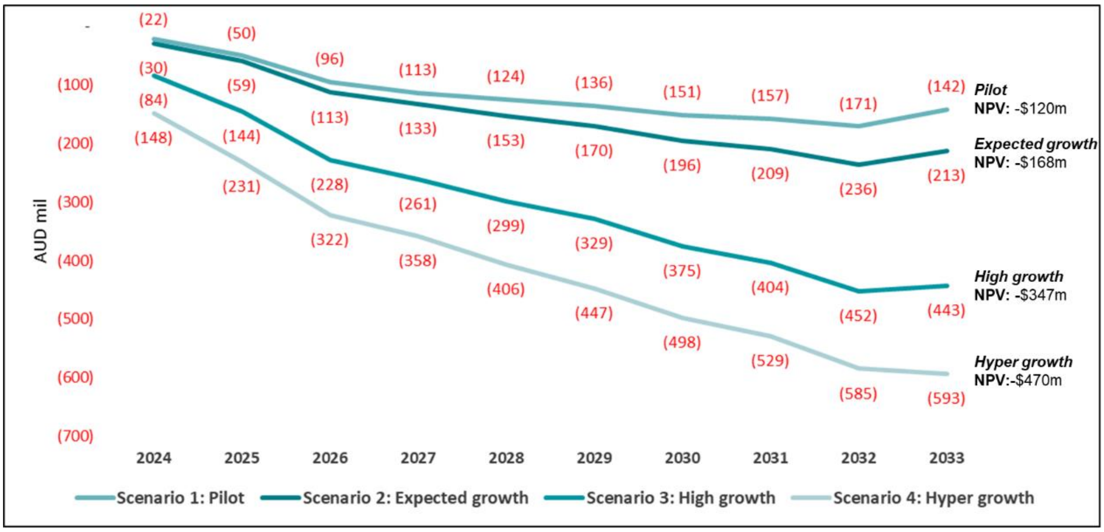

Figure 49: Combined undiscounted cashflow for NSS

The cost of NSS was determined by summing the availability payment and the energy payment. The energy payment was calculated by multiplying the number of NSS events and their duration by the total capacity of DESS enrolled within the VPP and the price paid per MWh. The cost of procuring NSS over a 10-year period, the potential capex deferral, and resulting NPV is provided in Table 24.

Modelling Scenario	Present Value of NSS fees	Present Value of Potential Capex Deferral	NPV
1: Pilot	$9	$30	$21
2: Expected	$9	$33	$24
3: High growth	$10	$40	$30
4: Hyper growth	$11	$33	$22

Table 24: Present value of NSS benefits and fees over 10 years (AUD mil)

Under the *Expected, High growth* and *Hyper growth* modelling scenarios, Western Power achieves a positive NPV noting that capex deferral can be achieved through NSS, when there is sufficient DESS capacity within the VPP and it is envisaged that in future additional capacity can be provided by including controllable A/C units in the VPP, as discussed in section 6.6.3. When NSS is delivered in isolation of the other energy services, the overall combined NPV, however, is negative under all modelling scenarios, shown in Table 25.

Whilst a reduction in network capex can be achieved through DER orchestration, it is noted that the Western Power's 10-year business plan estimates significant capital expenditure to deliver the DSO capabilities required to deliver NSS across the SWIS, which includes improving the visibility of the low voltage network, and uplift in advanced distribution management system (ADMS) and automation capabilities.

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$416	-$729	-$1,514	-$1,854

	Pilot	Expected growth	High growth	Hyper growth
Western Power	-$2	$4	$27	$25
AEMO	$122	$208	$334	$338
Customer	$261	$483	$1,066	$1,336
TPA	-$120	-$168	-$260	-$314
Combined net NPV (AUD mil)	-$219	-$267	-$446	-$470

Table 25: Combined NPV for NSS scenario (AUD mil)

As shown in the table above, the financial benefit of NSS is not distributed equitably and it is recommended that to improve the desirability for an Aggregator to provide NSS, an increase to the NSS price paid per MWh should be considered, such that it is, at a minimum, equivalent to the cost of delivering the NSS. However, it is important to note that any increase in price cannot result in the cost of procuring NSS to be greater than the cost of network augmentation. That is, the price ceiling of NSS is not market driven but valued against the cost of augmenting the network.

5.1.5 Constrain to Zero

CTZ is a potential new off-market NCESS offered by the DMO to instruct the aggregator to constrain energy output from contracted DER to zero export (net) or zero output (gross) at the NMI connection point. The design and application of CTZ is intended to be used as a pre-emergency service to mitigate minimum operation demand system issues that are also targeted by ESM, however the key difference being the CTZ is provided as an "opt-in" service.

As a pre-emergency service, the dispatch and pricing of CTZ is not connected to the energy market but is instead procured in advance of a forecast minimum demand day, instructing DPV within a VPP to constrain net solar export to zero. The expected impact of CTZ on a customer DPV export during a CTZ event is illustrated in the autumn and spring profiles shown in Figure 50, when the system load reached a minimum of 1,039 MW and net exports were curtailed to zero output between 11am and 3pm, but still allowing customers to self-consume gross solar.

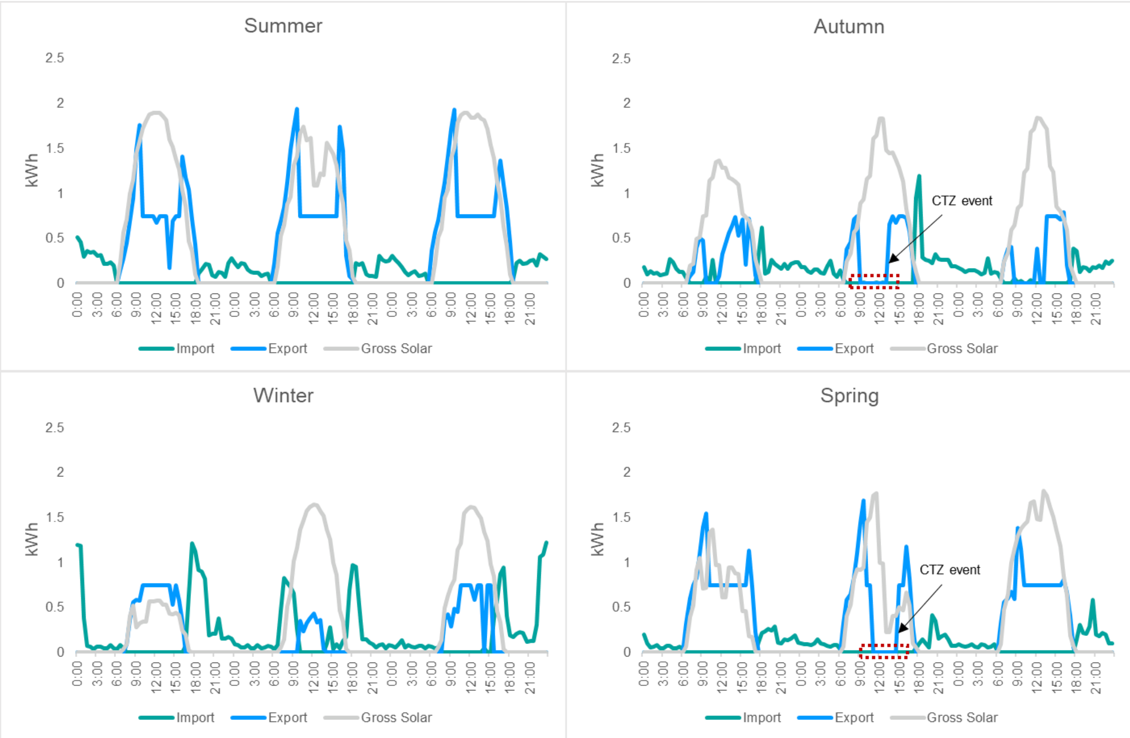

Figure 50: DPV only customer import and export profile CTZ scenario

In Figure 51 there is no discernible change to the battery state of charge, whereby gross solar exceeds exports and is used to charge the battery.

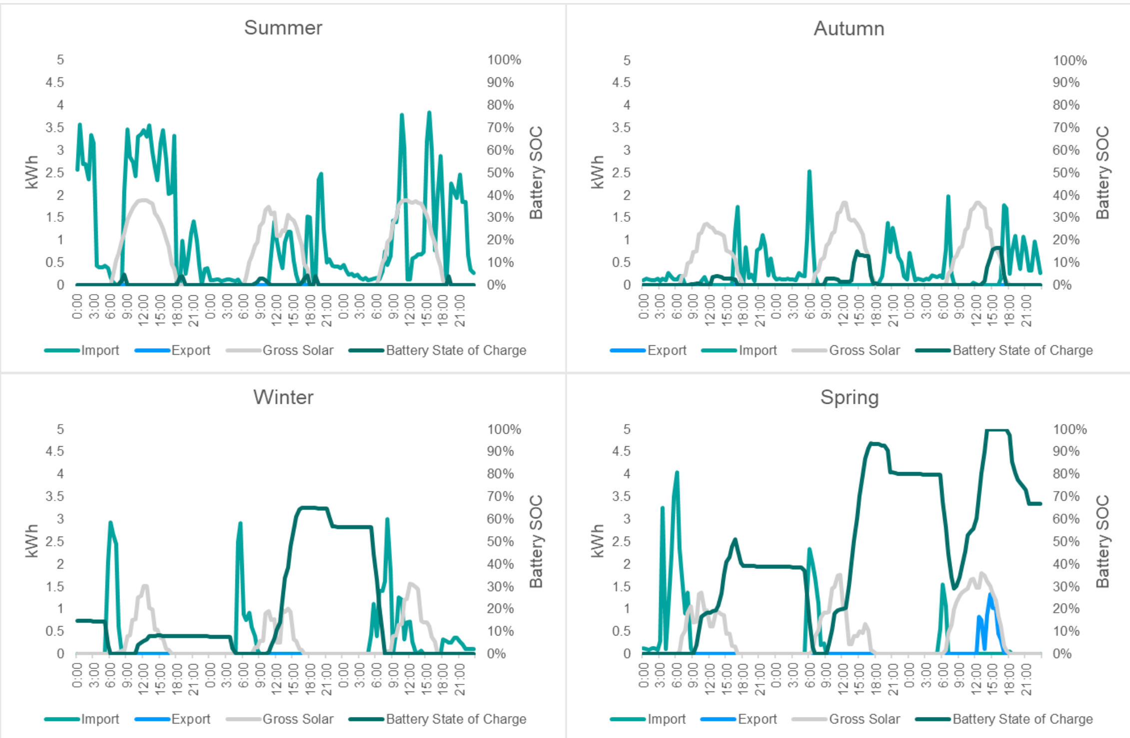

Figure 51: DPV and DESS customer import and export profile CTZ scenario

To support the development of the model, an indicative schedule of CTZ events that could be expected over the 10-year modelling period was developed. The schedule assumed five CTZ events between August and

December, with each event lasting 4 hours in duration, from 11am to 3pm, coinciding with high levels of solar irradiance at the time and where operational demand drops below the MDT.

The CTZ scenario only considers the curtailment of net solar exports and does not consider the curtailment of gross solar where all solar generation would be turned down to zero and it would be expected that consumption would increase as homes and businesses would need to import more energy from the grid. The decision to exclude the curtailment of gross solar was based on this being a similar function to ESM, which was not included within the scope of the CBA and as such the cost of implementing ESM has not been considered.

Changes to revenues and costs across the each of the four scenarios are summarised in Table 26 below, however, the payments for a limited number of CTZ events are insignificant compared to the revenue received by Synergy for retail energy and result in in minimal change over the modelling period.

	Difference to base case over 10 years (%)			
	Pilot	Expected growth	High growth	Hyper growth
Energy imports (MWh)	▼0.04%	▼0.05%	▼0.06%	▼0.08%
Energy exports (MWh)	▼4.69%	▼8.52%	▼17.74%	▼22.9%
Feed-in tariff paid to customer	▼4.12%	▼7.53%	▼15.63%	▼22.02%
Retail Revenue	▲0.06%	▲0.06%	▲0.09%	▲0.11%
Network Tariff Revenue	▼0.02%	▼0.03%	▼0.04%	▼0.04%
Energy purchased by Synergy from the WEM balancing market ($)	Min. change	Min. change	Min. change	Min. change
DER energy sold by Synergy to the WEM balancing market ($)	▼24.5%	▼24.67%	▼24.81%	▼24.85%

Table 26: Impact of CTZ changes compared to the base case

When considering the CTZ service in isolation (i.e., no other market or network services are delivered), the revenue earned by Synergy is significantly less than the costs incurred that are associated with the management of the Aggregator platform and customer recruitment costs. Likewise, Western Power and TPAs are not involved in the provision of CTZ and thus do not benefit from any revenue cashflows to offset their costs. Figure 52 below shows this, with the negative cashflows largely attributed to the low volume of CTZ events and associated price paid, which was based on the MDS activation price.

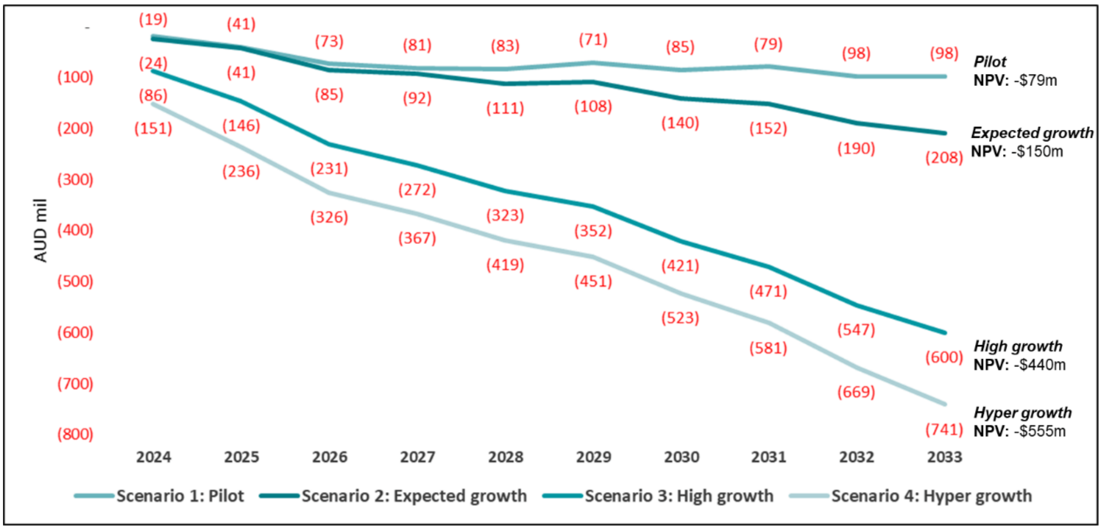

Figure 52: Combined undiscounted cashflow for CTZ scenario

Despite the negative combined cashflows, AEMO and customers do benefit and have a positive net NPV, as is the case with all DER orchestration scenarios. For customers, the value generated follows the same direction as the previous test scenarios with an increase in customer bills outweighed by the customer incentive payments. For AEMO, value is generated via decreases in system costs, such as MDS and Peak LFAS, with CTZ decreasing the MDS requirement further. As CTZ was modelled as an alternative NCESS to MDS, the difference in pricing constructs provides cost savings to AEMO. Though CTZ uses the MDS activation price, as DPV are free to provide other services and respond to CTZ events as required, CTZ does not include an availability price. MDS, however, requires assets to maintain the contracted capacity available, limiting available value sources, so does require an availability price. As such, increasing CTZ and reducing MDS results in a cost savings directly proportionate to the MDS availability price. The incremental undiscounted cashflows for the 10-year period for AEMO under the *Expected growth* modelling scenario reveal this, as shown in Figure 53:

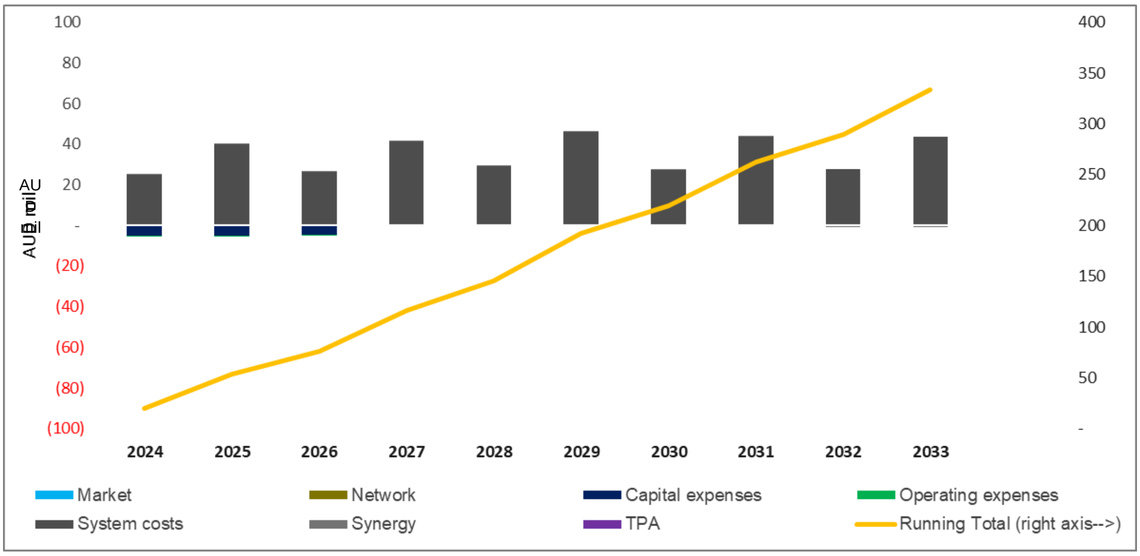

Figure 53: Incremental undiscounted cashflows for AEMO in the CTZ scenario (Expected growth)

As shown above, the payment made to Synergy as the aggregator providing the CTZ service is significantly outweighed by the additional cost savings from reducing overall system costs.

Reflecting the cashflows discussed above, the CTZ scenario has a negative net NPV when compared to the base case across all the modelling scenarios, with AEMO and customers generating a positive NPV.

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$354	-$674	-$1,516	-$1,852
Western Power	-$61	-$61	-$62	-$63
AEMO	$161	$237	$334	$340
Customer	$260	$483	$1,064	$1,334
TPA	-$85	-$134	-$260	-$314
Combined net NPV (AUD mil)	-$79	-$150	-$440	-$555

Table 27: Combined NPV for CTZ scenario (AUD mil)

A positive outcome for both Synergy and AEMO was, however, observed by increasing the MDT, which increases the number of CTZ events per year, resulting in increased payments for CTZ received by Synergy and a reduction in the volume of MDS that was required to be procured by AEMO.

As previously discussed, CTZ is a new and complex market concept due to the because of the interaction with ESM, where no compensation is offered to turn down gross solar exports and the operation of the Balancing Market.

In a fully operational Balancing Market where DER is integrated and appropriately managed, the expectation is that energy pricing would be enough to manage minimum demand during low-load periods and the negative price would penalise customers and aggregators for exporting energy and reward increased consumption. Negative pricing occurs due to downward pressure on the balancing price applied when demand is fully met by supply options that incur a loss when they do not generate, such as wind farms that create LGCs, and unscheduled generation, such as customer DPV. During these negative pricing events, Synergy's generation business is exposed to operational losses due to the wholesale energy price being below the feed-in tariff rate paid to DER owners, although retailers without a generation business potentially stand to profit by purchasing energy at a significantly reduced rate. Assuming Synergy is a net seller of energy in the wholesale energy market during negative pricing events, the CTZ scenario enables Synergy as both a generator and retailer to mitigate the impact of negative pricing by instructing DPV owners to curtail net exports to zero and offset any potential loss from the customer's feed-in tariff revenue. In this regard, there is additional potential value for Synergy as an aggregator in the reduction of exposure to these negative price events, which has historically been characterised by low operational demand.

An alternative to mitigate exposure to negative pricing and the increase of renewable generation would require additional investment in centralised energy storage to store excess generation during negative pricing periods, however this would incur capital cost which could be avoided if sufficient BTM storage capacity is available within a VPP.

5.1.6 Essential System Service – Contingency Reserve Raise

Contingency Reserve Raise is a market provided response to a locally detected frequency deviation and is used to restore frequency to an acceptable level when a underfrequency 'contingency event' occurs, such as the sudden loss of a large generator or load. An example of how ESS-CRR is used is to activate the rapid discharge of generation, such as discharging a fast response generator or DESS, to increase system frequency to an acceptable level. To provide this service, DESS must maintain a sufficient state of charge to be able to provide the scheduled capacity for 15 minutes.

Current capabilities, as tested in Project Symphony's pilot and modelled in the CBA, limit provision of ESS-CRR by a VPP through batteries, though this may be expanded to incorporate interruptible loads in the future as capabilities increase. As such, customers without a battery experience no change to their load profiles compared to the base case, as can be seen in Figure 54.

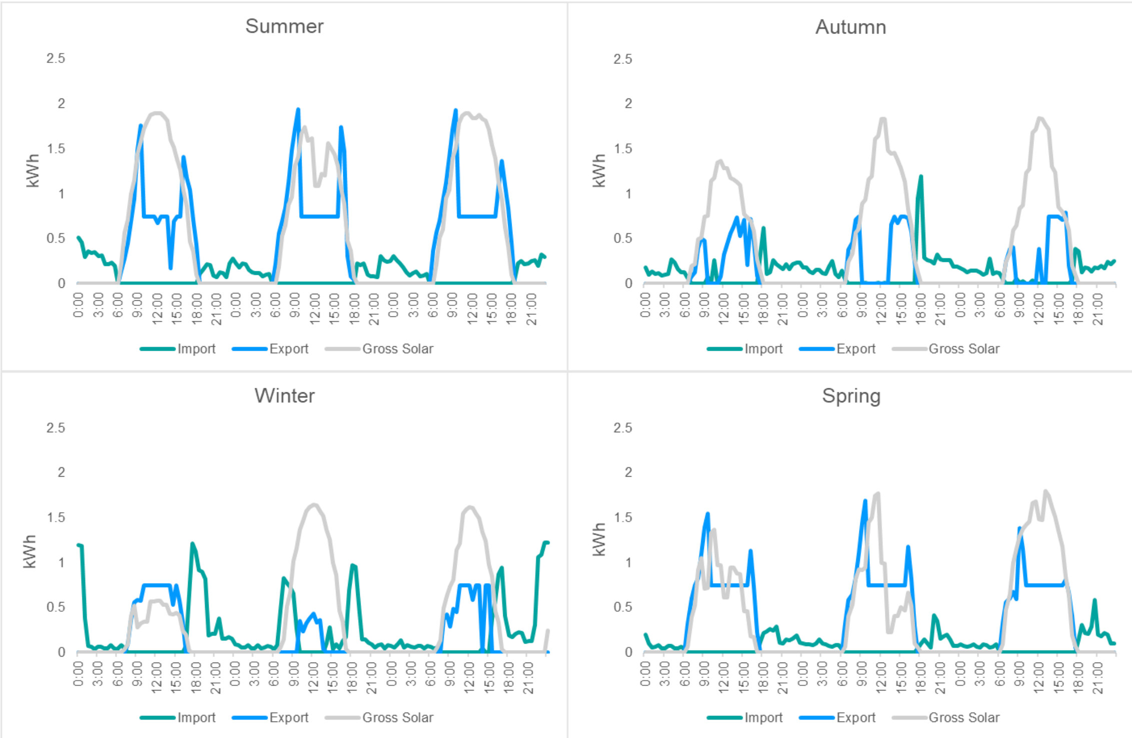

Figure 54: DPV only customer import and export profile ESS-CRR scenario

In the ESS-CRR scenario, DESS are required to maintain a sufficient level of charge to ensure they can be enabled for the service at all times. In Figure 55, the battery is observed to be maintain a constant state of charge waiting to be enabled to provide a contingency raise, rather than charging and discharging through the day to soak up excess solar. When an ESS-CRR service is enabled, on average, the battery will charge or discharge 10% of the enabled ESS volume (i.e., if a battery is enabled for 10kW of ESS-CRR in a 30-minute period, then the battery will discharge 0.5kWh over that period).

Figure 55: DPV and DESS customer import and export profile ESS-CRR scenario

The impact on customer import and exports and corresponding cashflows experienced by Synergy follows the same direction the NSS and CTZ scenarios experienced, as shown in Table 28: Impact of ESS-CRR changes compared to the base case

	Difference to base case over 10 years (%)			
	Pilot	**Expected growth**	**High growth**	**Hyper growth**
Energy imports (MWh)	▼0.04%	▼0.04%	▼0.06%	▼0.07%
Energy exports (MWh)	▼4.5%	▼8.21%	▼17.1%	▼22.05%
Feed-in tariff paid to customer	▼4.07%	▼7.4%	▼15.3%	▼22.39%
Retail Revenue	▼0.01%	▼0.01%	▼0.02%	▼0.02%
Network Tariff Revenue	▼0.02%	▼0.02%	▼0.03%	▼0.04%
Energy purchased by Synergy from the WEM balancing market ($)	Min. change	Min. change	Min. change	Min. change
DER energy sold by Synergy to the WEM balancing market ($)	▼23.58%	▼23.8%	▼23.97%	▼24.02%

Table 28: Impact of ESS-CRR changes compared to the base case

Like the other test scenarios, the change in exports can be attributed to the use of a 5kW static export limit under the base case, which results in greater curtailment when using DOEs due to exposing DPV to lower limits. A noticeable difference between the ESS-CRR scenario and the NSS and CTZ scenarios is the overall shape of the combined yearly undiscounted cashflows, as shown in Figure 56:

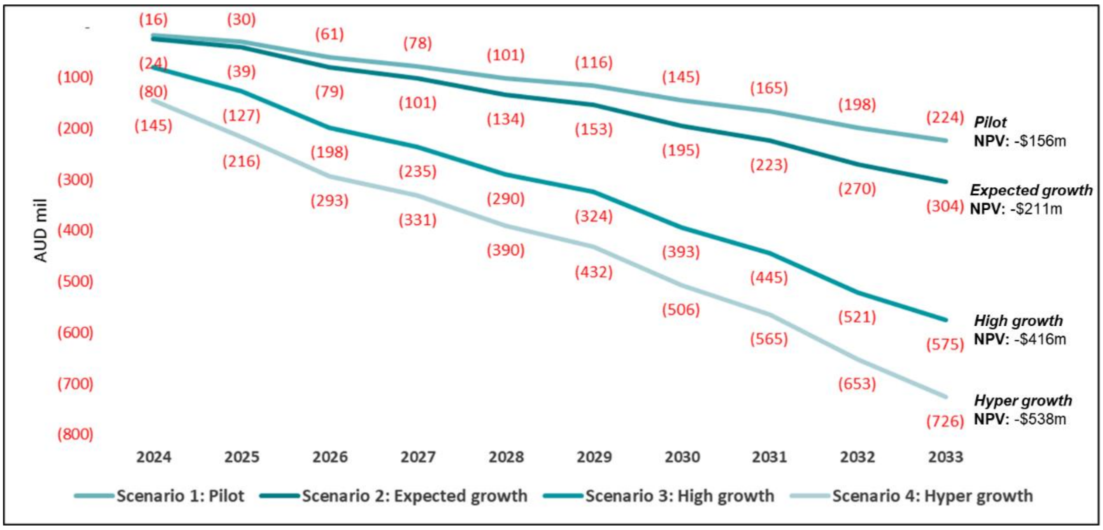

Figure 56: Combined undiscounted cashflow for ESS-CRR scenario

Where the cashflows for the NSS and CTZ scenarios were slightly more varied in direction, the ESS-CRR scenario reveals a definitive downwards trend in cashflows over the 10-year modelling period. This can be attributed to the disparity between the price received by the aggregator for providing the service and the incentive payment made to customers. The provision of contingency services is dependent on having enough DESS in the VPP that can provide a rapid discharge of energy to raise the frequency of the energy system. Under the ESS-CRR scenario, the NPV is negative due to the cost of recruiting DESS into the VPP outweighing the payments for ESS-CCR that are received by the aggregator. This is further reflected by a combined negative NPV of $156 million under the *Pilot* modelling scenario to a negative NPV of $538 million under the *Hyper growth* modelling scenario, as shown in Table 29:

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$423	-$738	-$1,526	-$1,868
Western Power	-$33	-$34	-$34	-$35
AEMO	$116	$201	$325	$327
Customer	$270	$493	$1,080	$1,352
TPA	-$85	-$134	-$260	-$314
Combined NPV (AUD mil)	-$156	-$211	-$416	-$538

Table 29: Combined NPV for ESS-CRR scenario (AUD mil)

5.1.7 Fully Orchestrated

Under the Fully Orchestrated scenario, the DER is enabled to provide the full range of services across the four test scenarios, effectively value stacking to gain the most value. Figure 57 reveals a typical load shape for customers with DPV but no battery when orchestrated for the Bi-directional Balancing Market and CTZ services:

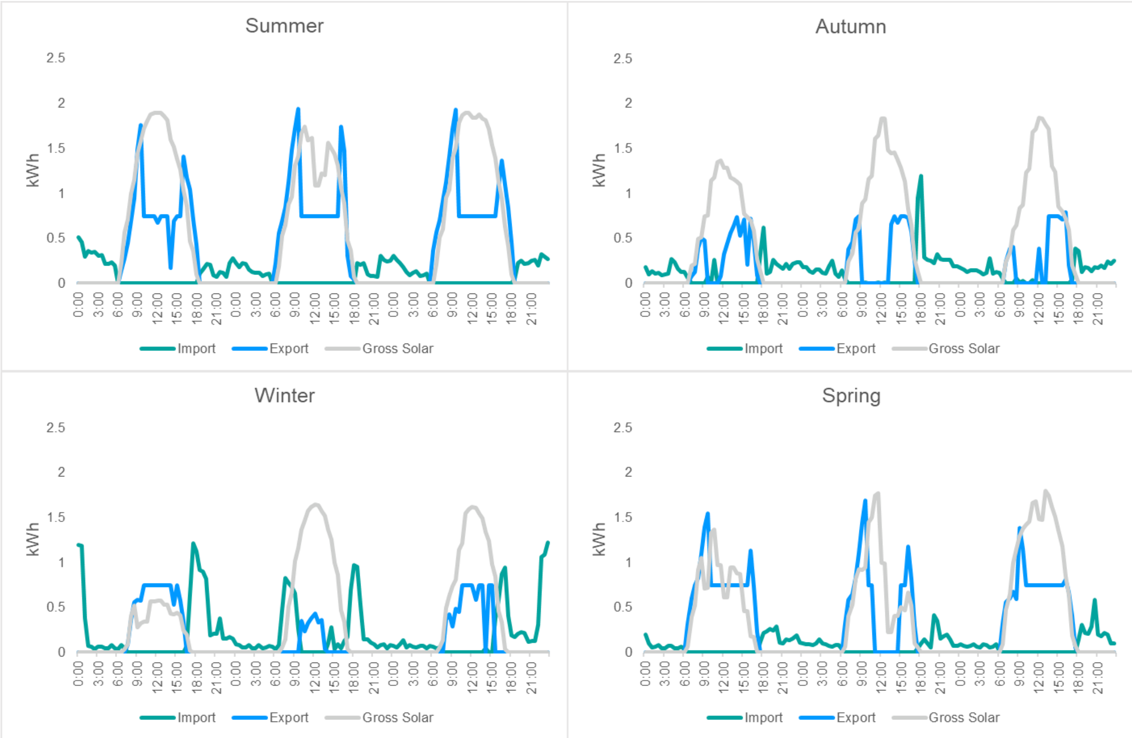

Figure 57: DPV only customer import and export profile Fully Orchestrated scenario

The profile in Figure 57 shows the DESS responding to different balancing price signals by charging and discharging the battery at different times of the day. In summer, the DESS draws down on stored energy during peak demand periods and recharges during the day. In winter, the battery begins to charge at 3am when the balancing price is low.

Figure 58: DPV and DESS customer import and export profile Fully Orchestrated scenario

The changes to revenues are consistent with the changes observed in the previous scenarios, whereby a reduction in energy imports results in a commensurate reduction in the purchase of WEM balancing energy. Whilst the changes are averaged over the 10-year period, it should be noted that the rate of change increases exponentially towards the later years as the number of DPV and DESS in the VPP increases. It is expected, however, that these will reach saturation if DPV and battery growth continues at the forecasted rate.

	Difference to base case over 10 years (%)			
	Pilot	Expected growth	High growth	Hyper growth
Energy imports (MWh)	Min. change	Min. change	▲0.01%	▲0.01%
Energy exports (MWh)	▼4.34%	▼8.1%	▼17.1%	▼22.06%
Feed-in tariff paid to customer	▼3.34%	▼6.61%	▼14.27%	▼19.86%
Retail tariff revenue	▲0.02%	▲0.02%	▲0.03%	▲0.04%
Network Tariff Revenue	Min. change	Min. change	Min. change	Min. change
Energy purchased by Synergy from the WEM balancing market ($)	▼0.2%	▼0.21%	▼0.3%	▼0.37%
DER energy sold by Synergy to the WEM balancing market ($)	▲214.15%	▲217.98%	▲220.29%	▲220.44%

Table 30: Impact of Fully orchestrated changes compared to the base case

Of note is that the decrease in customer exports is greater than the decrease in the feed-in tariff amount paid to customers. This is due to the use of batteries across the value stack, as mentioned above, results in batteries charging during off-peak time periods and discharging beyond self-consumption during peak periods. As a result, customer solar export for battery owners is effectively shifted to peak feed-in tariff times, enabling customers receiving the DEBS feed-in tariff to maximise the value of their time-of-use tariff.

The optimisation of services was modelled to generate the highest combined value between Synergy and customers for each trading interval, maximising the combined value stack and resulting in significant positive combined undiscounted cashflows each year across the 10-year modelling period, as shown in Figure 59:

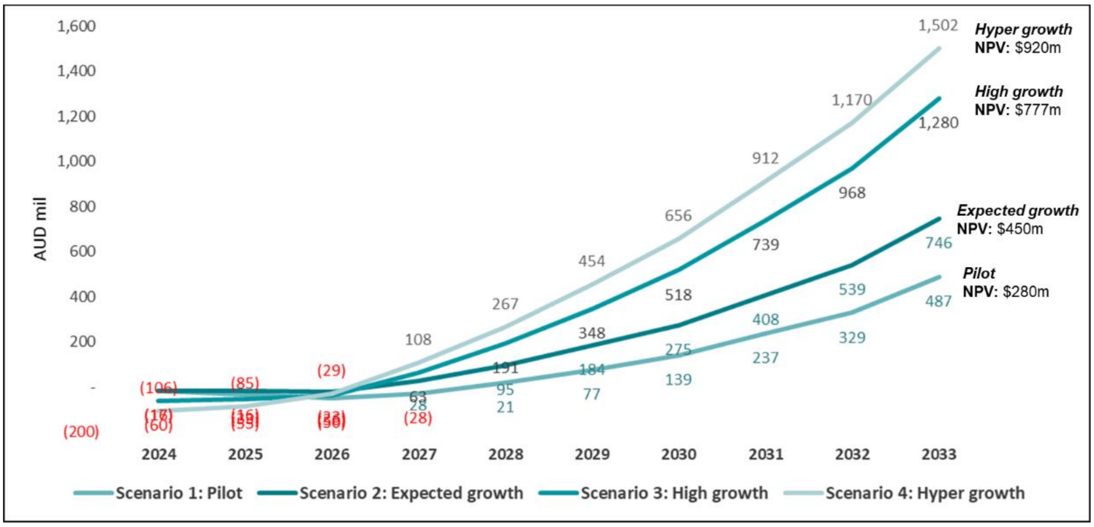

Figure 59: Combined undiscounted cashflow for Fully Orchestrated scenario

Under the Fully Orchestrated model, the combined NPV is positive for all modelling scenarios, which can be attributed in part to value stacking, whereby the delivery of DER services is co-optimised across the four scenarios to provide the maximum return.

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$29	-$122	-$391	-$476
Western Power	-$41	-$34	-$10	-$12
AEMO	$164	$247	$358	$370
Customer	$270	$494	$1,079	$1,352
TPA	-$85	-$134	-$260	-$314
Combined NPV (AUD mil)	$280	$450	$777	$920

Table 31: Combined NPV for Fully Orchestrated scenario (AUD mil)

Whilst the benefits associated with DER aggregation for Synergy are notionally associated with its role as the aggregator, the deferral of capital expenditure for generation to manage increased demand is also noted in Synergy's capacity as the State-owned generator. Whilst the cost of establishing new generation facilities is not wholly the responsibility of Synergy, the potential to defer the need for increased peaking generation or grid-scale battery storage provides additional value to Synergy and is discussed further in section 6.4.

From the perspective of Western Power, benefits across all four scenarios are evident through the deferral of network augmentation costs, where network infrastructure has been identified as being at or over capacity in the 2022 Network Opportunities Map which would result in costs to install an additional transmission transformer at an existing zone substation or establishing a new zone substation. Additionally, augmentation benefits at a distribution feeder and distribution transformer level were included at a high level, with the level of complexity required for detailed modelling of distribution feeder utilisation across the SWIS deemed outside the scope of the CBA. Across the 10-year modelling period, network investment deferral, due to DOEs as well as NSS, was estimated to provide cost savings with a NPV of $58 million for the Fully Orchestrated test scenario and *Expected growth* modelling scenario, providing a compelling case for orchestration. The results for Western Power, however, are heavily impacted by the estimated additional capital expenditure over the next 10 years required to scale Project Symphony's solution to the SWIS, as well as the estimated additional operating expenditure. Figure 60 demonstrates the impact orchestration has on network investment for the Fully Orchestrated test scenario and *Expected growth* modelling scenario, with an initial increase in investment followed by significant reductions:

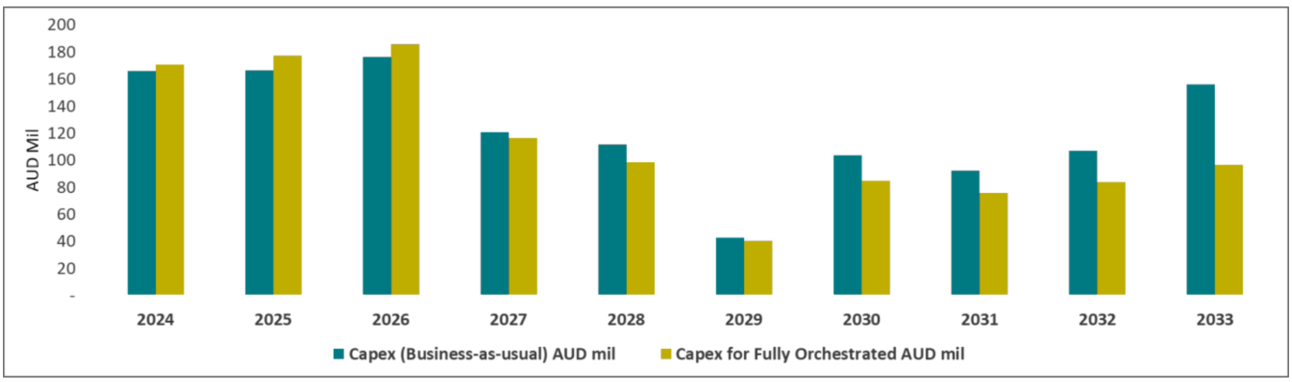

Figure 60: Annual undiscounted network capex for Fully Orchestrated test scenario (Expected growth)

As mentioned, the modelling did not include changes to network tariffs, however, improvements reducing the required investment to scale Project Symphony's solution to the SWIS would allow network augmentation deferral to have a flow-on effect, reducing the network tariff charged to Synergy, which could then be passed on to end-user customers via reduced retail tariffs. Additionally, it can be inferred that the deferral of network augmentation would have a positive externality on customers, where borrowing to fund additional network infrastructure can be significantly reduced, enabling State budgets to be redirected to other priorities.

The benefits of a VPP in the SWIS was assessed in work package 2.1, which surmised that there were broad societal benefits in enabling customers to access the electricity market that would not otherwise be accessible to end-use-customers; and would support the optimum economic value being derived from customer-owned DER assets. In addition to the potential benefits that could be achieved by customers under the right commercial setting, DER orchestration has the potential to add over 1,600MW in dispatchable generation capacity over the next 15 years,[141] which would generate significant benefit to the State by deferring the need for additional generation required to offset the phased retirement of 620MW of thermal generation in Muja by 2030.

5.1.8 Value from Dynamic Operating Envelopes

The testing of DOEs in the Pilot was expected to demonstrate how DOEs can be used to maximise the DER hosting capacity of the network, whilst maintaining safe network operating limits in consideration of design ADMD, discussed in section 3.3, *Network Support Services*. The value of DOEs becomes apparent when enabling larger DPV system to be connected to the network, which would otherwise need to be constrained by lower static export limits, reducing the value that can be achieved from larger DPV systems for both DPV owners and VPP participants. Initial modelling included an assumption that reduced the static export limit to 1.5kW per phase in the base case, to illustrate the positive impact of DOEs, where exports were higher in the orchestration test scenarios compared to the base case. In discussion with Western Power, it was subsequently decided that the existing 5kW static export limit should be used, as per the Basic Embedded Generation technical requirements, as there are no plans to change this requirement. Additional modelling would however be beneficial to consider the impact of connecting larger DPV systems and variations to the DOE schedules, which is discussed further in the section below.

Whilst the implementation of DOEs in the modelling would intuitively result in an overall increase in exports in the test scenarios, compared to the base case, this result was not observed, as illustrated in Figure 35. The lower-than-expected imports and exports in the test scenarios was attributed to the modelling assumptions used for the import and export limits and DPV capacity size used in the CBA modelling, which masked the value of DOEs. The base case assumed a 5kW static export limit for single phase customers, per Western Power's Basic Embedded Generator Connection Technical Requirements document and the modelled only considered 5kW DPV systems, reflecting the median monthly DPV capacity installed in the SWIS from June 2017 to May 2023, and noting that DPV systems with an inverter rating greater than 5kW are ineligible to receive the DEBS feed-in tariff. Additionally, the 5kW DPV system size reflects DPV systems recruited to the Pilot.

As DOEs are intended to adjust to the changing operating condition of the network, export constraints are only imposed at certain times, allowing higher export limits when there is available network capacity. In the base case, a 5kW static export limit on 5kW DPV systems does not impose any additional export constraints as the export capability is equivalent to the size of the system. In addition, increasing the export limit to 15kW in the orchestration test scenarios does not result in an increase in exports from 5kW DPV systems.

[141] Western Power, Synergy, AEMO, & Energy Policy WA, 2022c. *Project Symphony: DER Service Report*. p.10

The impact of a 5kW or 15 kW export limit would however be observed in larger DPV systems (e.g., > 5 kW), where DPV have an increased capacity to export energy compared to smaller 5kW DPV systems. As the DOEs implemented a 1.5kW limit during minimum demand days, which was not used in the base case, DPV exports in the orchestration test scenario were subjected to an additional constraint that were no imposed in the base case.

The orchestration test scenarios implemented DOEs for DPV managed under a VPP, with the static export limit used in the base case still applied to customer DPV that are not participating in the VPP. Due to the need to calculate binding DOEs in the Pilot to test DER compliance, time-series data of DOEs included DOEs that were not necessarily reflective of network constraints. As such, the CBA model assumed the default DOE used in the Pilot, which applied a set limit to different times of the day. To improve this reflecting real DOEs, the default DOE was only applied to minimum demand days and the day immediately following a minimum demand day, with all other days having a higher export limit applied.

The lower customer DPV exports in the test scenarios, compared to the base case (in Figure 35) is supported by the findings in the *Distribution Constraints Optimisation Algorithm Report* completed in WP 4.1. The report shows the 5kW static limit and increasing DPV penetration resulting in customers participating in the VPP experiencing a decrease in payments from energy buyback schemes. Though not included in the CBA modelling, the analysis conducted as part of WP 4.1 also shows decreasing export limits as participation increases. This is due to the VPP being allocated a set portion of available network capacity (ANC) to be distributed between its participants, so as more customers participate, the ANC must be shared across more participants. As such, with participation aligned to the *Pilot* modelling scenario, export limits are set at 15kW. However, with participation aligned to the *Hyper growth* modelling scenario, this reduces to 6.5kW, and a scenario in which 80% VPP participation is achieved reduces this further to a 4kW export limit.

As ADMD increases, the import and export limits required to maintain safe operating limits within the network are likely to decrease, resulting in either increased constraint placed on imports and exports or increased network augmentation. As such, continued growth in the volume of DPV connections and capacity of DPV systems is unlikely to support the continued use of a 5kW static export limit in the long term and may result in an overly conservative view of the hosting capacity available on the network, potentially restricting or delaying the connection of customer DPV or driving the need for unnecessary network augmentation. This is supported by the findings of the analysis completed in WP4.1. In other jurisdictions such as South Australia, DNSPs have started to lower the static export limits to 1.5kW for customers that are not assigned a DOE, and it is feasible that this export limit could be lowered to zero export in the future under an unmanaged DPV scenario, which may indeed be necessary as larger DPV systems are connected to the network (e.g., greater than 10kW).

Impact of larger DPV systems

As previously discussed, the 5kW static export limit used in the base case, negates the maximum value that can be derived from DOEs, if the system size of DPV is limited to 5kW. That is, the value of DOEs should enable larger systems to be connected to the network, where the capacity of the network can accommodate larger systems. Whilst the CBA focused on extrapolating the asset engaged in the Pilot VPP to the rest of the SWIS, using the existing 5kW connection limit for single phase, it was acknowledged that would be merit in understanding what additional value could be gained by VPP participants if larger DPV systems were connected to the network. Sensitivity analysis was therefore conducted to assess how value generated by orchestrating DER via a VPP could be impacted when larger DPV systems are installed.

To model an appropriate representation for larger DPV systems, NEM DER connection data was used which indicates an increasing trend for residential customers to install DPV systems between 10kW to 15kW, with the current average having already increased to 9.59kW in September 2023.[142] In consideration of this trend, additional modelling considered a scenario where customers install 10kW DPV systems instead of the 5kW DPV systems that has been modelled in the CBA. The cumulative number of 10kW systems compared to all other DPV for the modelling period is shown below:

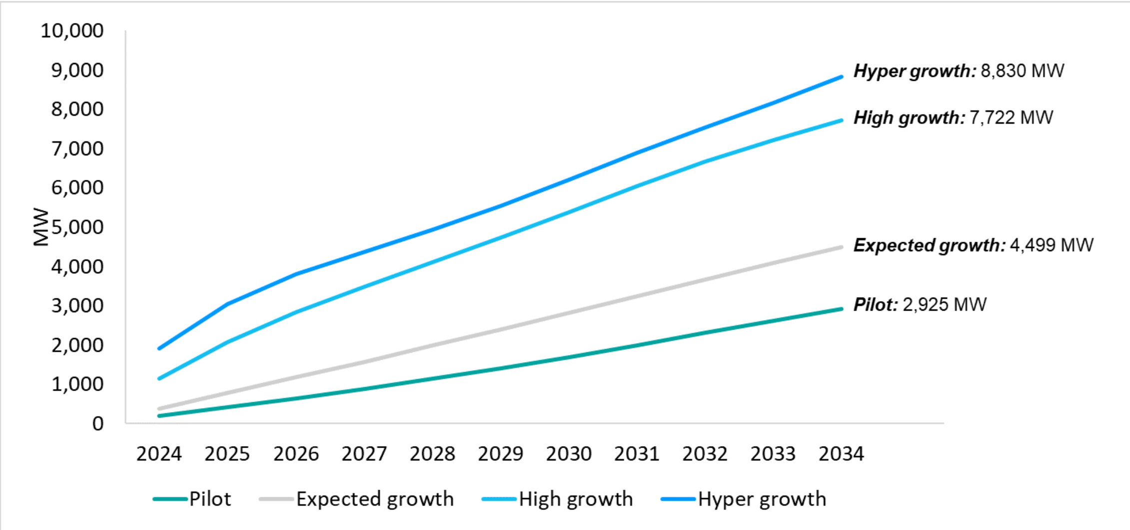

Figure 61: Cumulative 10kW DPV capacity in VPP across modelling scenarios

In addition to increasing the size of DPV systems, changes to the DOE limits, shown in Table 32, were also considered to further assess how DOEs influence the CBA results. The export limits for single-phase and three-phase systems were increased to 6.5kW (from 1.5kW and 4.5kW respectively) from 10am to 3pm on minimum demand threshold days and exports limits are reduced to 10kW (from 15kW and 22.5kW respectively) for the same period on all other days, when compared to the original modelling assumptions.

		12am – 10am		10am – 3pm		3pm – 12am	
		Import	**Export**	**Import**	**Export**	**Import**	**Export**
Minimum demand day	Single-phase	15kW	15kW	15kW	6.5kW	15kW	15kW
	Three-phase	22.5kW	22.5kW	22.5kW	6.5kW	22.5kW	22.5kW
All other days	Single-phase	15kW	15kW	15kW	10kW	15kW	15kW
	Three-phase	22.5kW	22.5kW	22.5kW	10kW	22.5kW	22.5kW

[142] Vorrath, 2023. Another solar record falls as average rooftop PV system size hits new high | Renew Economy

Table 32: Alternate DOE export limits

Compared to the energy flows discussed in section 5.1.1, the larger DPV size results in lower customer imports due to a greater ability to self-consume, as shown below:

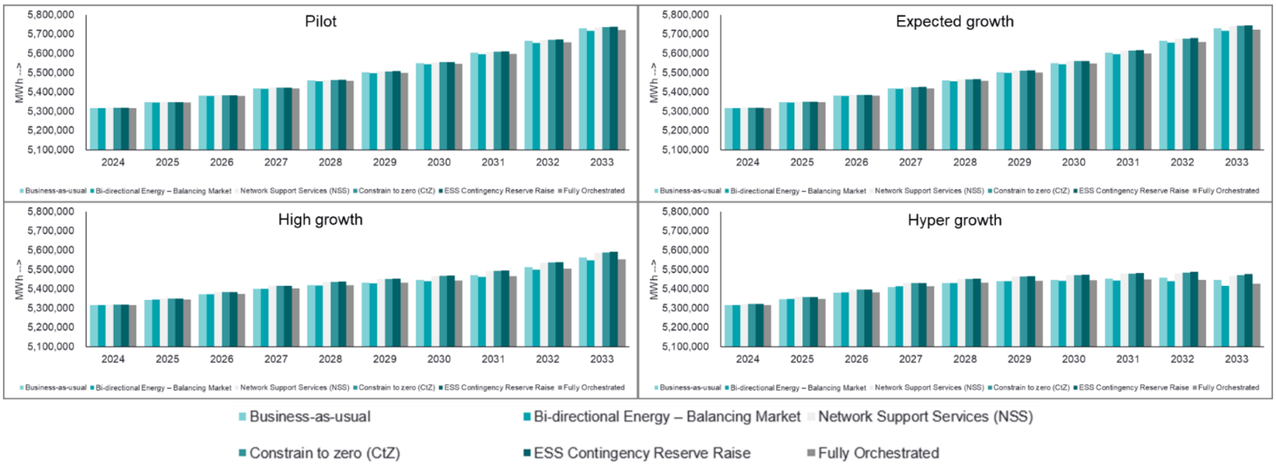

Figure 62: Energy import by customers with 10kW DPV and updated DOEs (MWh)

In terms of exports, Figure 63 reveals the connection of 10kW systems results in a noticeable increase in the total volume of energy exported to the grid by DPV and DESS owners in all of the DER orchestration test scenarios compared to the base case; and when compared to the results for the 5kW DPV systems in Figure 35, despite the updated DOEs constraining on a more regular basis.

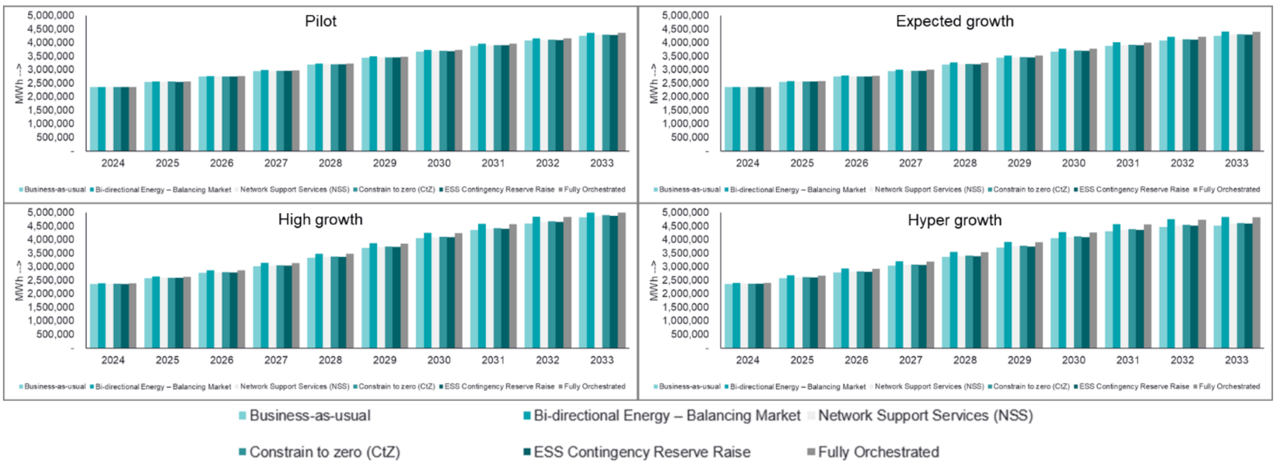

Figure 63: Energy exports by customers with 10kW DPV and updated DOEs (MWh

The increase in total exports in the test scenarios is attributed to the increased output from the larger capacity DPV systems, which irrespective of the lower DOE export limit of 10kW from 10 am to 3pm on "all other days", still enables greater exports when compared to the lower static 5kW export limit used in the base case and assigned to DPV that are not participating in the VPP.

The combined NPV for the Fully Orchestrated test scenario, with the inclusion of 10kW DPV systems, is positive for all modelling scenarios and there is an overall increase in value compared to the 5kW DPV system assumption reported in sectionFully Orchestrated5.1.7.

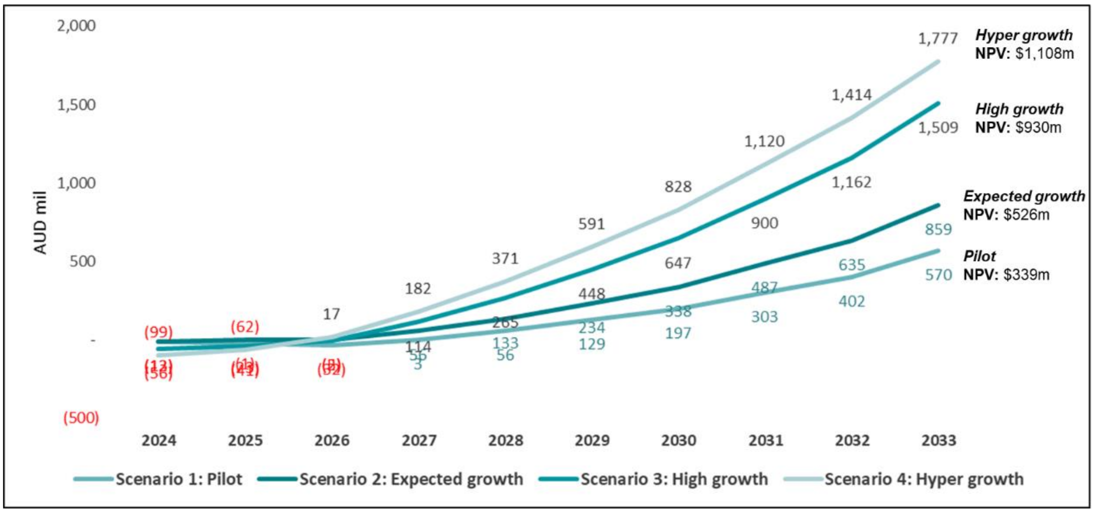

Figure 64: Combined undiscounted cashflow for Fully Orchestrated scenario with 10kW DPV systems

As shown in Table 33, the increase in value compared to the 5kW DPV assumption is attributed to the increase in benefits for AEMO and customers. In relation to AEMO, the increase is due to increased capacity of managed DPV compared to unmanaged DPV in the system. Whilst for customers, a reduction in imports and increased exports complement one another to generate greater value.

	Pilot	Expected growth	High growth	Hyper growth
Synergy	-$30	-$135	-$412	-$499
Western Power	-$42	-$36	-$11	-$13
AEMO	$179	$261	$380	$396
Customer	$318	$571	$1,233	$1,539
TPA	-$85	-$134	-$260	-$314
Combined NPV (AUD mil)	$339	$526	$930	$1,108

Table 33: Combined NPV for Fully Orchestrated scenario with 10kW DPV systems (AUD mil)

It is clear from the sensitivity analysis that enabling larger DPV connections demonstrate the potential value DOEs provide to the system, as well as customers. However, the sensitivity only considers the impact of changes to two variables within the CBA modelling: DPV size and dynamic export limits. As such, it is unable to provide an accurate view of how that value may be distributed when coupled with different commercial arrangements, if larger DESS were installed, nor when considering factors out-of-scope of the CBA. Therefore, it is recommended further analysis be undertaken to accurately assess the potential value generated from a whole-of-system perspective, as well as determine how that value may be distributed equitably across all participants.

5.2 Distribution of Value

To assess and optimise the value of DER orchestration for VPP participants, it is important to understand how value is distributed across each participant and what changes can be made to equitbly share the benefits of orchestration amongst VPP participants. Although a positive NPV was reported in the Bi-directional Balancing Market and Fully Orchestrated scenarios, the distribution of value across each of the project stakeholder groups varied depending on the test scenarios considered within the Pilot. This is particularly evident when reviewing the undiscounted yearly cashflows for each project participant, as shown in Figure 65:

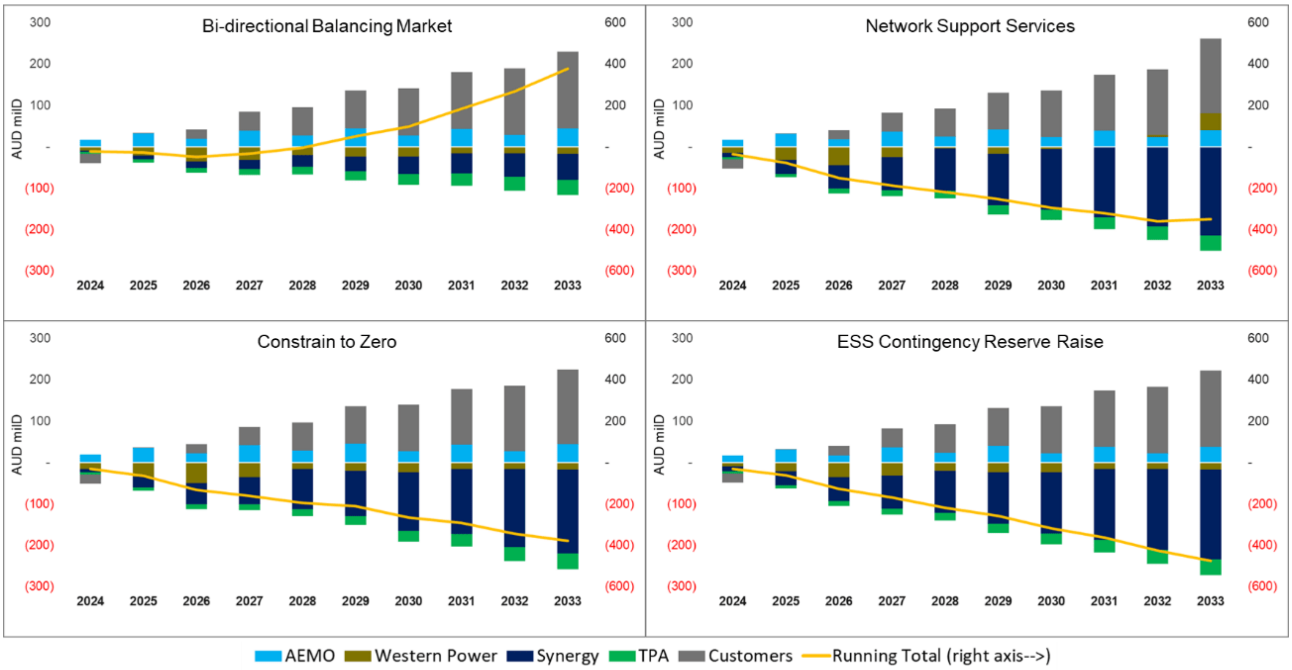

Figure 65: Value distribution across test scenarios under the Expected growth modelling scenario

As expected, value distributed to Western Power is higher under the NSS test scenario compared to others shown above, with NSS providing a direct benefit to the network in terms of network augmentation. Under the other three test scenarios, Western Power bears the full cost of scaling Project Symphony's solution to the SWIS whilst not receiving any direct value. Similarly, Synergy as an aggregator receives the largest share of the value generated under the Bi-directional Balancing Market test scenario, where it can sell energy generated by customer DPV in the VPP to the market and take advantage of the small energy arbitrage opportunities present. In comparison, they are unable to take advantage of this value source in the other test scenarios shown. AEMO receives the most value from the CTZ test scenario due to CTZ further reducing the MDS requirement compared to the other test scenarios.

Although, cost recovery mechanisms in place for Western Power and AEMO as regulated businesses ensure costs and savings are passed on to other market participants, the recovery of cost and distribution of benefits such as capex and opex savings or cost avoidance, were not included in the CBA modelling. To support further discussion and analysis, a high-level and indicative view of how these cost recovery mechanisms might impact the value distribution of the Fully Orchestrated test scenario is shown below. However, it is recommended that more detailed analysis should be undertaken to reflect actual cost allocations.

	Pilot	Expected growth	High growth	Hyper growth
Synergy	$98	$93	-$41	-$117
Western Power	$0	$0	$0	$0
AEMO	$0	$0	$0	$0
Customer	$270	$494	$1,079	$1,352

TPA	-$85	-$134	-$260	-$314
Other market participants	-$4	-$3	-$1	-$1
Combined NPV (AUD mil)	$280	$450	$777	$920

Table 34: Indicative impact of cost recovery mechanisms on value distribution in the Fully Orchestrated test scenario (AUD mil)

To reallocate the costs and savings to Synergy, shown in Table 34, it is assumed that 65% of market and system operations fees received by AEMO are attributed to Synergy as the largest market participant, with the remaining other 35% attributed to other market participants not covered in the scope of the CBA. 100% of the reduction in LFAS and MDS costs, compared to the base case, and the recovery of costs to provide ESS-CRR and CTZ services are also passed onto the Synergy from AEMO. In addition, as the main customer of Western Power, it was assumed that 90% of Western Power's network revenue is attributed to Synergy via the network tariff and as such a change in Western Power's costs or revenue could be reflected in a change to the network tariff. As mentioned, the percentages used to show the pass through of costs and benefits are an indication only and should not be considered as an accurate reflection of cost recovery impacts.

Passing through the reduction or increase in Western Power's revenue and costs results in an improvement to Synergy's NPV due to a portion of the cost savings that AEMO receives from reduced system costs being passed on to Synergy, however, this is tempered by the pass on of increased costs from Western Power arising from costs to scale Project Symphony's solution to the SWIS. As VPP customers and TPAs are not market participants, there is no change to the value distributed to them, however it is expected that the benefits of DER orchestration should be addressed through the commercial VPP engagement model and changes to retail tariffs for customers that are not enrolled in the VPP.

It is important to stress that this is an indicative view only as there are a multitude of factors not considered that impact how cost recovery mechanisms operate. For example, factors relating to Synergy's generation business, with generation not included in the modelling, have not been captured in this report. Additionally, examples of two factors not reflected in this indicative view that are prevalent in the CBA modelling include:

- The costs and benefits not covered by cost recovery mechanisms, such as capital expenditure or reduced costs due to efficiency gains for Western Power, versus those that are covered.
- The method for calculating the pass on of Contingency Reserve services costs to each individual market participant versus the method used in relation to MDS costs.

As such, it is recommended that additional whole-of-system modelling would be beneficial to accurately reflect the impact of cost recovery mechanisms in the WEM, and to determine the optimum distribution of value to each market participant when orchestrating DER via a VPP with cost recovery mechanisms considered.

Value received by customers and TPAs remain largely the same across all test scenarios shown in Figure 65, which is carried through to the Fully Orchestrated test scenario. The undiscounted yearly cashflows of each participant when value stacking under the Fully Orchestrated test scenario is shown in Figure 66:

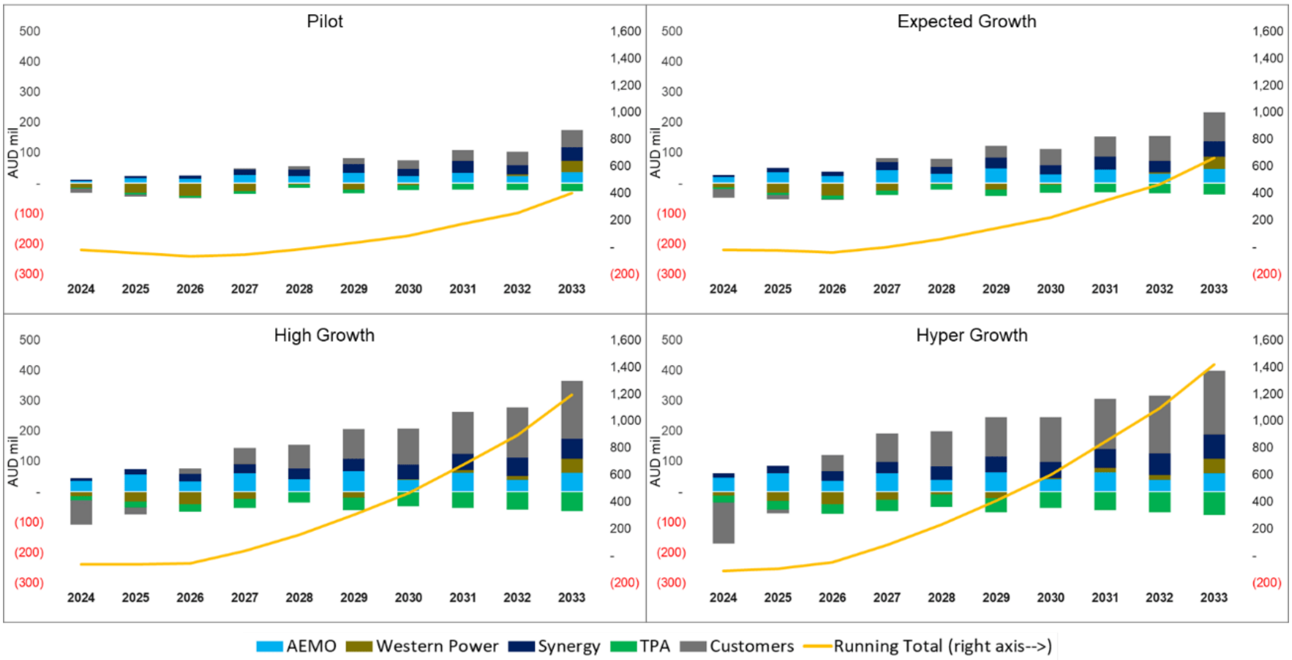

Figure 66: Value distribution of the Fully Orchestrated test scenario

As shown above, value is maximised across all participants under the Fully Orchestrated test scenario. The table below provides a breakdown of this, showing the present value of the costs and revenue for each participant in the Fully Orchestrated test scenario compared to the base case.

	Pilot	Expected growth	High growth	Hyper growth
Synergy				
PV of Revenue	$442	$695	$1,294	$1,587
PV of Costs	-$471	-$817	-$1,685	-$2,063
Western Power				
PV of Revenue	$0	$0	$0	$0
PV of Costs	-$41	-$35	-$10	-$12
AEMO				
PV of Revenue	$9	$16	$33	$40
PV of Costs	$155	$231	$325	$330
Customers				
PV of Revenue	$444	$769	$1,586	$1,940
PV of Costs	-$173	-$276	-$507	-$588
TPAs				
PV of Revenue	$66	$111	$226	$277
PV of Costs	-$151	-$246	-$486	-$591

Table 35: Present value of costs and revenue for participants in the Fully Orchestrated test scenario

As mentioned, the value Western Power receives relates to cost savings arising from network augmentation deferral. However, this is overshadowed by the required investment to scale Project Symphony's solution to the SWIS. Additionally, the RT1 reference tariff modelled only considers the energy imported by customers, measured at the meter, and does not consider the volume of energy exported.

Network tariffs provide one avenue through which Western Power can recoup the cost of managing the network. The shift towards bi-directional energy flow in the network requires increased network augmentation to address increased prevalence of localised voltage issues. However, the RT1 reference tariff fails to compensate for this shift and the required mitigation of associated constraints. Therefore, in the absence of network tariff changes and other cost recovery mechanisms, the result is clear: the current network tariff structure fails to cover increased use of the network.

Like Western Power, value distributed to AEMO is mainly in the form of cost savings, with a reduction in system costs providing a net benefit compared to the base case. Though measured as value distributed to AEMO, this also represents the value provided to market participants collectively, with the cost savings resulting in a decrease in cost passed through to market participants by AEMO's cost recovery mechanisms. The value distributed to Synergy and TPAs reflects the commercial arrangements used in the Pilot, which focused on a payment per asset model rather than being tied to the type or amount of service provided, resulting in revenue and costs to be fixed across all test scenarios. As such, with greater VPP participation, both participants' costs (i.e., payments to customers) increase at a greater rate than their benefits. For TPAs, this benefit is the payment received from Synergy for each asset they enrolled in the VPP. For Synergy, the benefits are related to the four services they provided via the VPP. Conversely, as customers' costs rise, such as their electricity bills, the total value of incentive payments received from Synergy and TPAs increase at a greater rate. As a result, customers receive a disproportionate share of the value of a VPP.

Though customers receive a disproportionate share of value, this is not distributed amongst individual customers equally. This is mainly due to the orchestration payment afforded to DPV only customers but not DPV and DESS customers. Figure 67 provides a view of the value distributed to a single customer for the two types of customers modelled, showing the incremental yearly undiscounted cashflows across the 10-year period under the Fully Orchestrated test scenario:

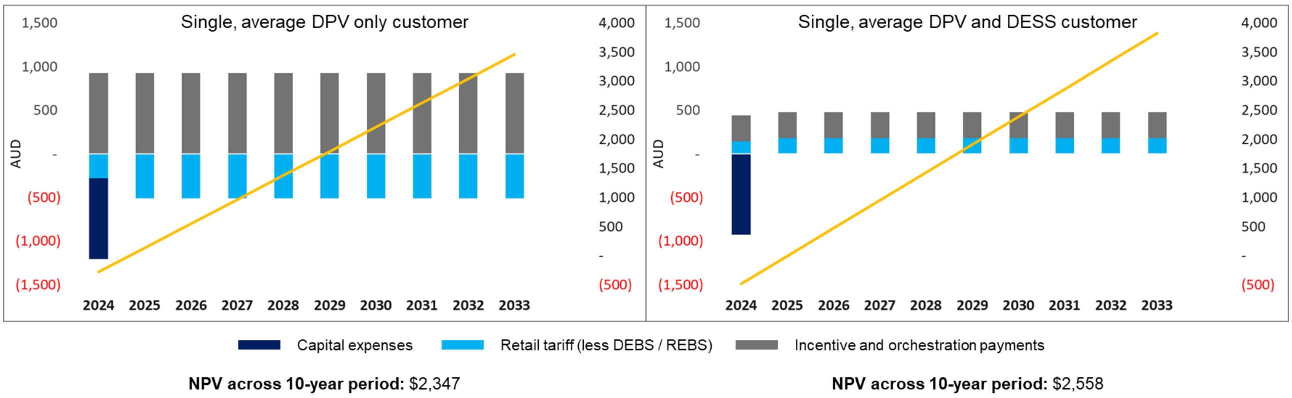

Figure 67: Incremental yearly undiscounted cashflows for a single customer in the Fully Orchestrated test scenario[143]

As shown, customers joining the VPP with a battery receive greater value overall compared to customers only enrolling a DPV system. However, it is important to note that the graphs shown above are the incremental cashflows, that is, the difference in cashflows between the base case and the Fully Orchestrated

[143] As the figure represents a single customer, the variables considered in the modelling scenarios do not apply.

test scenario. As the capital cost of the DESS is assumed to incur regardless of orchestration, this cost for the DPV and DESS customer, equal to $16,000 in the first year, is not represented.

Despite DPV only customers receiving additional benefit compared to DPV and DESS customers, due to the orchestration payment afforded to them to compensate them for a reduction in solar generation, the increase in their electricity bills reduces their NPV to below that of DPV and DESS customers. Customers with a DESS, though not provided with the additional payment, experienced a slight reduction in their electricity bills, as mentioned previously. Another key difference relates to the breakeven point, where customers receive value equal to their initial investment. Customers joining the VPP are expected to bear some costs relating to communications and data collection equipment. As shown, the additional orchestration payment afforded to DPV only customers results in them receiving a benefit that almost covers the initial investment made in the first year ($924 paid to cover a cost of $926), with the increase in their electricity bill resulting in them reaching their breakeven point in just over one year. In comparison, DPV and DESS customers only receive $300 each year in incentive payments ($150 per asset). When incorporating the reduction in electricity bills, these customers require just over two years to reach their breakeven point. This difference results in DPV and DESS customers requiring longer until they see a return on their investment, which could disincentivise customers from enrolling their DESS. Regardless, the high disparity of value provided to customers as a whole compared to other participants reinforces that the commercial constructs used in the Pilot were not commercially viable and reflects their purpose of rapid recruitment of customers.

As discussed previously, customer DESS has a greater potential for value when orchestrating via a VPP compared to DPV due to capabilities to participate in more service offerings, such as NSS and ESS-CRR, and enable access to other revenue streams not considered within the scope of the Pilot. However, noting the incentive payments in the Pilot were to rapidly attract customers to participate and not for a commercially viable VPP, any incentive that potentially incentivises customers to not enrol their DESS is likely to limit the battery capacity a VPP has available. Hence, it is crucial the commercial constructs are designed to provide greater incentive to customers with a DESS than those with DPV only, ensuring battery capacity is maximised.

Additionally, the payments made to TPAs need to reflect the total value the VPP provides the aggregator, namely, Synergy. One simple, though rudimentary, example is to remove the additional orchestration payment DPV only customers receive and increase the fixed annual payment to $300 per asset, as well as increasing the payment to TPAs by 200%. The impact this has on the value distribution is shown in Figure 68:

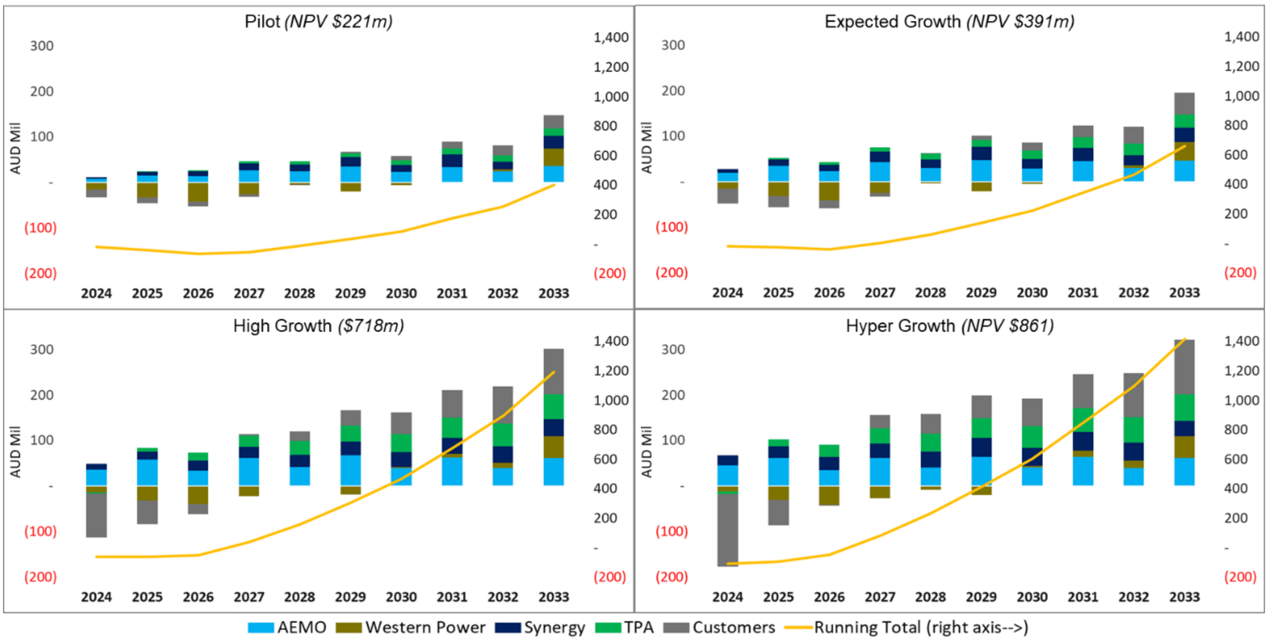

Figure 68: Value distribution with varied commercial arrangements

Such a rudimentary change has a significant impact on the value distribution, providing a higher equitable distribution across Synergy, TPAs and customers. The NPV under these varied commercial arrangements for each of the participants across all modelling scenarios is shown below:

	Pilot	Expected growth	High growth	Hyper growth
Synergy	$101	$135	$174	$218
Western Power	-$41	-$34	-$10	-$12
AEMO	$164	$247	$358	$370
Customer	$8	$13	$62	$104
TPA	$48	$89	$193	$239
Combined NPV (AUD mil)	$221	$391	$718	$861

Table 36: NPV of participants with varied commercial arrangements (AUD mil)

Though ostensibly self-evident, it is worth noting that changes to cashflows have a flow on effect to another stakeholder or group of stakeholders. The change to the commercial arrangements causes an increase in the NPV for Synergy and TPAs, bringing both into positive values, whilst decreasing the NPV of customers, though they remain positive. As such, changes to commercial arrangements need to be met with care and require significant market research to ensure an attractive service for customers whilst remaining an attractive market for TPAs, Synergy, and other potential aggregators who may enter the market to serve contestable customers. The table below outlines some of the commercial variables present in Project Symphony and provides considerations relating to each.

Variable	Considerations
Incentive and orchestration payments	Financial incentives provide a mechanism to attract customers to participate in the VPP and to ensure that they are no worse off. Customers with new or existing DPV but no DESS were paid an annual orchestration payment, levied against the capacity of their DPV system ranging from $310 to $773 per year, but were still entitled to earn REBS or DEBS from solar

Variable	Considerations
	exported to the grid. In addition to orchestration payments, customers received $150 for each DER asset enrolled in the VPP (unless they received a subsidy during the Pilot for the purchase of a new asset paid by way of an energy credit on their electricity bill). These payments represent a significant ongoing cost to the aggregator, which will continue to increase as more customers join the VPP. As mentioned, reducing the payment customers receive for participating in the VPP has a positive effect on the aggregator, however, also results in a reduction of equal value for customers. Though customers can have their payments reduced and still maintain their NPV positive position, it could also act as a disincentive to participate or reason to withdraw from the VPP and should be approached with caution. For example, if there is a 20% reduction in the annual incentive payments from $150 to $120 to enrol DER assets in a VPP, the Aggregator will avoid $21 million in incentive payments over 10 years (under the Fully Orchestrated and *Pilot* modelling scenario) and an equivalent reduction in payments received by customers, whilst still remaining NPV positive. An alternative approach to consider would be changing the commercial engagement model from an incentive-based model to a subscription-based model, where customers pay to participate and receive the financial benefits of the VPP. Under the Fully Orchestrated test scenario and *Pilot* modelling scenario, an annual payment of $23 per registered DER from a customer to the aggregator, would result in Synergy breaking even over the 10 years (e.g., NPV 0), whilst the customers would still achieve a NPV of $348 million over 10 years, compared to the $441 million where $150 is received per DER asset. It is also recommended that in lieu of a flat DER asset payment, further consideration should be given to paying different rates based on the actual value that the DER asset provides the VPP, whereby higher incentives may be paid for, and to attract, DESS or load following devices that can provide an injection of energy or load smoothing, compared to other less valued DER. Similarly, consideration should be provided to the size of DER assets, maximising capacity by actively seeking larger systems.
TPA payments	TPAs reveal a negative NPV due to bearing the full cost of orchestration relating to the integration of their systems with the Aggregator Platform, system access fees, and payments to customers. Though they receive revenue from Synergy, the value of this benefit is outweighed by these combined costs. This can be linked to two major factors. The first is that the benefit TPAs receive is directly proportionate to the number of customers they have. The second is that the benefit received is also dependent on the commercial arrangement they have with the aggregator, in this case, Synergy, and ensuring arrangements are commercially viable. This is shown above, where the benefit TPAs received is increased by 200%. With no other changes made, TPAs enjoyed a NPV positive position as a result. As such, the potential value TPAs receive could be significantly larger than shown in the modelling if they are able to successfully enter more attractive arrangements and maximised through attracting greater numbers of DER.
NSS payments	In the Pilot, the DSO paid the Aggregator an energy rate of $125/MWh for firm NSS. This payment significantly undervalues the benefits received by NSS and is outweighed by the costs of recruiting enough batteries to provide the service. Targeting larger commercial DESS (e.g. 1MWh) or grid connected battery storage and paying a higher energy rate would likely increase value for both the DSO, maximising the available capacity and therefore potential value of NSS by maximising network investment deferral capabilities, and the aggregator, who would have increased certainty on the demand for NSS, enabling it to enter into longer term contracts and incentivise investment to procure facilities in locations where NSS is required, further ensuring available capacity for NSS at those locations. The use of larger DESS and grid connected battery storage is explored further in section 6.6.2.
Network tariffs	The network tariffs paid to Western Power reflects the amount of energy that is imported by

Variable	Considerations
	consumers from the grid. However, this does not consider the use of DPV and DESS to export back to the grid and, with the expected increase in uptake of these systems, it is likely this will compound local voltage issues in the network. The introduction and transition to cost reflective tariffs (e.g., two-way tariffs) for flexible DER are intended to reflect the cost to DNSPs to manage the network as a result of increased DER penetration. As customers ultimately bear the cost of any upgrades required to the network, through changes in the network tariff, there are benefits in progressing tariff reforms that encourage the efficient use of the existing network and minimises the need for network investment.
System costs	The number of DPV owners participating in a VPP contributes to cost avoidance for AEMO through reduced LFAS and MDS costs. However, the cost of enrolling customers to the VPP is largely borne by Synergy (as the aggregator) or TPAs, and further modelling is required to show how the benefit of reduced system costs to AEMO (when DPV are managed under a VPP) are passed onto market participants.

6. Recommendations to scale DER orchestration in the SWIS

The Pilot undertaken in Project Symphony was limited to four test scenarios and a subset of DER assets that were recruited to the VPP in the Pilot area. Although the VPP also included controllable loads such as hot water systems and air conditioning systems, due to the lack of statistically significant data for hot water and systems and some measurement issues encountered during the Pilot relating to air conditioners, the value of these DER assets could not be assessed and were excluded from the CBA model. The Pilot also included a grid connected battery and commercial battery towards the end of the stability period which demonstrated positive potential value, however due to the limited statistical representation within the Pilot area, they were also excluded from the CBA model. As a result, the Pilot represents a subset of potential applications and benefits of DER orchestration that might be achieved. It is therefore recommended that future pilots and trials should consider the inclusion of grid connected and commercial sized BTM batteries and controllable loads to assess the additional applications and use cases that can be supported by these DER assets.

DER orchestration at scale across the SWIS has the potential to defer or minimise significant large-scale investment in network augmentation, generation and large-scale grid connected storage, by providing a broader and more diverse range of alternatives to new facilities investment and at a more cost-effective means of supporting the power system and at the least cost to the consumer. To illustrate the quantum of these benefits, AEMO estimated that $1.8 billion in grid-scale storage could be avoided if 20% of firming capacity was provided by DER storage in the NEM. This benefit increased to $4.4 billion in avoided expenditure if 50% of storage capacity could be provided by BTM DER.[144,145] Whilst it is expected that the benefit value in the WEM would be lower compared to the NEM, there is still potential to defer significant expenditure.

A summary of opportunities and suggested areas for further investigation that should be considered to access the full potential of DER orchestration in the SWIS is provided below and discussed in further detail in the sections following:

1. Optimising commercial arrangements to distribute value equitably.

Ref No.	Recommendation
1.1	Conduct in-depth market analysis to develop potential commercial models to scale the VPP in consideration of other VPP pilots and product offerings used in other jurisdictions.
1.2	Transition to bi-directional time-of-use network reference tariffs that reflect the cost of managing increased flow of energy in the network and enable increased price signalling for investors in the market.
1.3	Conduct further analysis to understand the impact of passing through avoided or deferred expenditure to customers and market participants, through reduced market participation fees and changes to network tariffs

2. Alternative incentives to increase customer participation in VPPs.

Ref No.	Recommendation
2.1	Develop educational programs to provide customers with knowledge of the benefits they receive from enrolling their DER in a VPP, how their DER will be used in a VPP and the impact to their energy use, and how customers will be able to monitor VPP control of their DER. *(Currently being progressed as per the DER Roadmap.)*

[144] AEMO, 2021c. *2021 Inputs, Assumptions and Scenarios workbook*
[145] AEMO, 2021d. *2021 Inputs, Assumptions and Scenarios Report*

2.2	Explore the social licensing and impact on customer sentiment of mandating VPP participation for different DER.
2.3	Provide finance mechanisms to reduce the up-front investment required by customers or introduce power purchase agreements, increasing accessibility of VPP participation.
2.4	Utilise build-to-rent schemes to increase VPP participation and take advantage of larger DER.
2.5	Consider mechanisms that enable renters to invest in and/ or install DER without needing to be a homeowner, increasing accessibility of VPP participation. *(Currently being progressed as per the DER Roadmap.)*
2.6	Introduce DER specific retail tariffs that enable customers to minimise energy bills via the use of DESS and flexible loads, incentivising investment in these DER, as well as VPP participation. *(Currently being progressed as per the DER Roadmap.)*

3. Transition to dynamic connection contracts and enhanced use of DOEs.

Ref No.	Recommendation
3.1	Undertake additional testing and targeted recruitment of larger capacity DPV systems (e.g., > 10kW) to test DOE capabilities in managing larger systems.
3.2	Explore the use of dynamic connection agreements with customers in the WEM directly to enable DOEs outside of VPP participation and allow larger DER to be connected.
3.3	Review Western Power's basic embedded generation technical requirements document in consideration of DOEs.

4. Reducing capital and operating costs.

Ref No.	Recommendation
4.1	Target recruitment of customers on the basis of zone substations to ensure hardware costs are incurred efficiently.
4.2	Explore the use of alternative data collection equipment and approaches to decrease required capital expenditure, including the feasibility of mobile data recorders to complete compliance checks rather than continuous compliance monitoring.
4.3	Conduct in-depth whole-of-system modelling to assess the value of DER orchestration via a VPP for generation businesses, including the impact on generation emissions.
4.4	Identify key geographical areas with high penetration of DESS to maximise potential services that may be provided, with consideration given to NSS as a localised service, and adopt a targeted recruitment approach.
4.5	Include a section in the Network Opportunities Map specific to NSS and potential capacity required for different geographical areas as an investment signal to VPPs.

5. Accessing the value of DER in other energy services and markets.

Ref No.	Recommendation
5.1	Test DER capabilities to provide Contingency Reserve Lower services, Regulation services, and System Restart services, as well as capabilities to participate in the RCM, and conduct whole-of-system modelling to assess the value of a VPP orchestrating DER for use in all electricity markets in the WEM.

6. *Maximising the types of DER assets that can provide orchestration services.*

Ref No.	Recommendation
6.1	Develop a consistent set of connection standards and communications protocols for connecting EV charging infrastructure to the network and review the connection process to streamline connection of EV infrastructure. *(Currently being progressed as per the DER Roadmap.)*
6.2	Develop EV-specific charging tariffs to incentivise investment in EV charging infrastructure in areas of the network deemed by the network operator to provide the most benefit or least cost of network augmentation. *(Currently being progressed as per the DER Roadmap.)*
6.3	Test EV capabilities in a future pilot and conduct whole-of-system modelling to assess the benefits of including EV capabilities in a VPP. *(Currently being progressed as per the DER Roadmap.)*
6.4	Test the capabilities of grid connected batteries in a future pilot and conduct whole-of-system modelling to assess the benefits of including these in a VPP compared to residential BTM DESS, determining an optimal asset mix.
6.5	Test air conditioner capabilities in demand management and load shifting (e.g., pre-cooling of homes) in a future pilot and conduct whole-of-system modelling to assess the benefits of including air conditioners as a flexible load in a VPP.
6.6	Ensure flexibility in customer contracts allowing customers participating in a VPP to opt-in or opt-out for each of their specific DER assets being controlled to provide each service.
6.7	Test electric hot water system capabilities in a future pilot, targeting recruitment in specific locations of the network with emerging or existing constraints to ensure successful testing regarding use for NSS, and conduct whole-of-system modelling to assess the benefits electric hot water systems can provide via a VPP.
6.8	Ensure statistically significant representation of different types of electric hot water systems in future testing and compare the value associated with each type.
6.9	Consider implementing government schemes to reduce customers' up-front cost of upgrading from a gas hot water system to an electric hot water system to increase uptake of these DER assets.

The recommendations listed above and the issues they address are discussed further in the following sections, including case studies on concepts that were out-of-scope of Project Symphony but provide important insights relating to the scalability and potential additional value of DER orchestration. Though not exhaustive, the case studies provided in the sections below were identified as relevant to the future of DER orchestration in the WEM.

6.1 Optimising commercial arrangements to distribute value equitably

Commercial arrangements between Synergy, TPAs, and customers

The commercial framework used in the Pilot to recruit and incentivise customers was established specifically for the purposes of conducting the Pilot, testing desirability of a VPP product offering to the market and recruiting a minimum number of DER assets required to test the technical viability of the VPP model and associated platforms. Testing of different retail tariffs and other commercial frameworks, therefore, were out-of-scope of the Pilot. As shown in Table 12, a variety of DER orchestration payments were used to provide a financial incentive to customers, depending on whether the DER asset was new or existing, which then determined if the customer received a subsidy to purchase the DER (e.g. a new battery, hot water system or upgraded air conditioner) or an annual pro-rata payment for existing DER (e.g. DPV).

The annual pro-rata payments enabled existing DER owners to participate in the VPP, with customers receiving payments related to the number of assets they chose to enrol and, for those with a DPV system but no battery, the size of their system. However, it was not anchored to the actual utilisation of their DER during the Pilot. The absence of a unit-based approach meant that the distribution of benefits across all customers on this contractual arrangement was disproportionate to the impact to their home energy costs or convenience. Whilst the recruitment and engagement model provided a sufficient basis for the purposes of the Pilot, the commerciality of this model, compared to other more complex commercial arrangements, requires further consideration. Aggregators and TPAs will need to develop a compelling offer that demonstrates that a DER customer would be better off overall if they choose to participate in a VPP as compared to the benefits that they would already receive as a standalone DER owner.

As previously discussed in section 5.2, two alternative commercial arrangements were assessed to address this. The first involved increasing the TPA payment from Synergy by 200% and increasing the fixed annual payment for all customers to $300 per asset but removing the orchestration payments afforded to DPV only customers, which results in a more equitable distribution of value. The second considered a shift from an incentive-based model to a subscription-based model, where customers paid the aggregator $23 per annum to participate in a VPP (in lieu of receiving the $150 per annum payment per DER asset), which would result in Synergy breaking even, whilst the customer remained NPV positive, assuming nothing else changed. The value under the subscription model passed to DPV only customers included the orchestration payment used in the Pilot. DPV and DESS customers, though not receiving any payment under this model, received a decrease in their electricity bills due to the control of their batteries, which optimises import of energy from the grid to occur during super off-peak and off-peak periods, maximising the value gained from the time-of-use retail tariff.

Another possible commercial model is to determine incentive payments as a percentage of the value generated for each service provided, with an additional annual payment for customers with DESS to incentivise customer investment and drive recruitment of DESS into the VPP. In testing additional commercial models for sensitivity, the CBA considered the use of such commercial arrangements for customers and combined it with a cost-based model for payments from Synergy to TPAs. Table 37 provides a summary of the changes to the commercial arrangements between Synergy, customers, and TPAs:

	Mark-up on Customer Costs	Mark-up on Platform Costs	Customer Payments (% of revenue generated by VPP)	Annual Payment for DESS Customers
Synergy	-	-	90%	$150
TPA	20%	60%	100%	$150

Table 37: Alternative commercial arrangements tested for Fully Orchestrated scenario

The alternative commercial arrangements provide TPAs a mark-up on their costs, ensuring revenue gained from Synergy is above those costs and providing a positive profit margin, reflecting realistic market constructs rather than those used in the Pilot. Payments to customers determined as a percentage of the total value generated by the VPP for services provided provides increased flexibility, ensuring both Synergy and the TPAs only pay for services customer DER provide, rather than a fixed cost, whilst maintaining positive revenue streams. Additionally, by the TPA providing a greater margin than Synergy, the market reflects different customer incentives that are likely to occur, providing customers with choice (though for simplicity, the ratio of customers enrolling via Synergy to TPAs remained the same). TPAs, by applying a mark-up to the customer costs, can attribute 100% of the value generated by customer DER in providing services and still maintain net positive cashflows. In comparison, Synergy is unable to do this due to holding the responsibility as the market participant and parent aggregator. One important factor is the ratio of customers joining via Synergy compared to TPAs, with different ratios impacting the portion of value able to be distributed to customers. Finally, the fixed annual $150 payment used in the Pilot was maintained, though only awarded to customers enrolling with a DESS to show increased incentive that could potentially drive customer investment in batteries. The resulting undiscounted cashflows over the 10-year period for the Fully Orchestrated test scenario under the *Expected growth* modelling scenario is shown below:

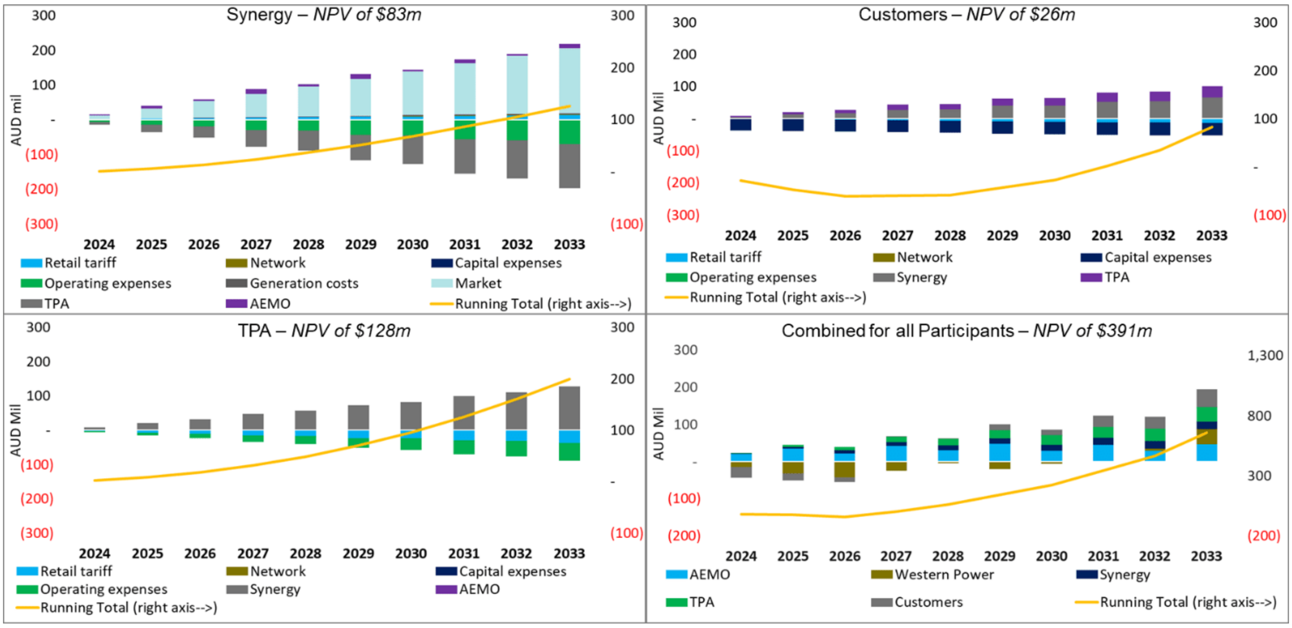

Figure 69: Yearly undiscounted cashflows with alternative commercial arrangements

By adopting commercial arrangements based on margins applied to value and costs, the value distribution is also improved. As expected, the combined NPV across all participants remain the same at $391 million, with only the value distribution being impacted. This reinforces the benefit of implementing value-based and cost-based commercial arrangements.

As such, with testing of different commercial models not included in the Pilot, a key recommendation is for future pilots to consider alternative commercial arrangements to ensure equitable distribution of value across participants and ensure the implementation of a VPP is attractive for aggregators and TPAs as well as customers. Therefore, in-depth market analysis is required to guide pricing strategies.

Transition to bi-directional time-of-use network tariffs

Consideration must also be given to the current network tariff arrangements. As discussed in section 5.1.8, residential customers are classified under the RT1 reference tariff charged to Synergy, in proportion to the volume of energy imported by customers as measured at the meter, with network tariffs developed to provide one form of cost recovery mechanism for the network operator, Western Power. However, as they reflect the original design of the network, they fail to consider the increasing shift towards bi-directional flow of energy. This results in network augmentation required as a result of the increase in bi-directional energy not being captured under the current tariff structures. Implementing bi-directional network reference tariffs would ensure the increased use of the network, and subsequent increase in network investment, is captured under this cost recovery mechanism. This is particularly prevalent regarding implementing a VPP, which results in an overall increase in the volume of energy being traded in the WEM, discussed in section 5.1.1. As such, bi-directional network tariffs would also assist in distributing more value to Western Power, resulting in a more equitable value distribution.

Complementary to bi-directional network tariffs is the use of time-of-use network tariffs. By implementing tariffs that charge different prices for use of the network during different periods, Western Power can incentivise shifting of energy use to coincide with periods of low demand on the network. Western Power's Access Arrangement 2022/23 – 2026/27 acknowledges the need for tariffs based on time of use to align changing energy demand in super-off peak, peak, shoulder and off-peak periods, and propose a gradual transition from the current time-of-use arrangements to new time-of-use services for new connections from the AA5 effective date.[146] When combined with the introduction of a VPP, this provides an additional price signal to the VPP to control customer DER to import and export energy during optimal times on the network, reducing the impact of both high customer operational demand, as well as high solar irradiance corresponding with low operational demand.

Both bi-directional network reference tariffs and time-of-use network tariffs provide increased price signalling to market participants. By controlling customer DER, aggregators are uniquely positioned to take advantage of these types of tariffs, due to capabilities to directly influence timing of customer imports, enabling them to enjoy lower costs compared to other market participants. This, in turn, increases investment in the market. The benefit to Western Power is increased management of the network, with these types of tariffs, when used together, minimising times where network use deviates from safe operating bands and the number of local constraints occurring as a result. Therefore, it is recommended to progress network tariff reforms to introduce new bi-directional time-of-use network reference tariffs.

6.2 Alternative incentives to increase customer participation in VPPs

Whilst the Pilot demonstrated the operational and technical capability of the platforms to respond to different scenarios, achieving the maximum value of DER orchestration is dependent on customers agreeing to participate in the VPP. As mentioned, the commercial arrangements need to be reviewed to ensure equitable value distribution, however, this results in less direct financial incentives provided to customers, which could hinder VPP participation. As such, alternative approaches to incentivising VPP participation need to be considered.

Firstly, to support the use of alternative commercial arrangements, targeted education programs should be developed to improve customers' understanding of opportunities to take advantage of DER, how their energy is used within a VPP, and a simplified way of monitoring the benefits that they receive in near-real time. This would assist in marketing VPP participation to customers by presenting an attractive product offering, whilst also providing customers with the knowledge needed to make informed decisions regarding choosing to participate in a VPP via Synergy or via one of the available TPAs.

Secondly, in the absence of an attractive commercial arrangement that drives an increase in VPP participation by improving the value passed through to customers, other regulatory instruments could be considered such as mandating all new DER connections to be assigned to an aggregator to increase participation.

Finally, the upfront capital cost of DER, as well as individual circumstances (such as if a customer is renting), can be a potential barrier for some customers and requires attention to determine ways these barriers can be overcome. By mitigating the barriers, customer VPP participation can increase, enabling more customers to access the benefits of DER. Some possible options to address these are provided in Table 38.

Initiative	Description
Reducing customer's upfront DER costs	As mentioned, the VPP participation rate is a main factor relating to value realised by the VPP. The upfront capital cost of DER is an identified barrier that may prevent some customers from accessing the cost saving benefits of DER, as well as VPP participation. This may also leave

[146] Economic Regulation Authority, 2022e. *Draft decision on proposed revisions to the access arrangement for the Western Power Network 2022/23 – 2026/27*, "Attachment 11: Network tariffs"

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Initiative	Description
	them potentially exposed to increased energy costs should there be a change to retail tariffs. Policy measures or the provision of financial products that provide improved access to DER in return for a service and / or credit-based payment plan could be explored by retailers and aggregators to increase enrolment within VPPs and to support existing DER owners to upgrade their systems as their needs change or assets reach the end of life.
Solar Power Purchase Agreements	Residential and commercial solar Power Purchase Agreements (PPA) are emerging within the NEM, which aims to provide customers with access to the benefits of DER, without the upfront capital cost. Under a typical PPA, the DPV is owned, installed and managed by the PPA provider and the energy consumed by the householder is charged at a rate that is typically lower than the tariff offered by the retailer to supply energy from the grid. The PPA provider is then able to use the energy generated as part of a VPP. This could increase accessibility to DER for customers, increasing overall VPP participation.
Build-to-rent schemes	Build-to-rent (BTR) schemes are another emerging trend that is gaining momentum within Australia to combat access to affordable accommodation. A report published by EY for the Property Council of Australia identified potential benefits of BTR schemes and recommendations to incorporate DER within BTR property developments.[147] In BTR schemes, land and property developers are incentivised to develop affordable housing, which is then rented in lieu of sale, in return for tax incentives. Under BTR schemes, developers could be incentivised or mandated to install DER as part of their development and enrolled within a localised BTR VPP or embedded network that supplements the energy needs of the local area.
Social housing and rental properties	The criteria for Pilot participation included a requirement that the customer owned the home (outright or with a mortgage, thus excluding rental properties from participation). Given that approximately 69% of WA households own their own home outright or with a mortgage,[148] lower socio-economic groups and renters are unlikely to benefit from DER due to the cost of DER or lack of incentives for property owners to install DER on rental properties. Whilst the WA government has established a number of schemes to support home ownership, affordable housing remains out of reach for some, whilst others may opt out of home ownership for lifestyle reasons. The largest VPP trial in South Australia, aims to address the equitable access to the benefits of DER by enabling tenants to install a 5kW DPV and DESS in return for participating in the VPP and paying a discounted tariff for their energy consumed.[149] In alignment with Action 20 in the DER roadmap, the implementation of a similar retail product that enables these customer groups to receive the benefits of DER and increase VPP participation could be considered.
Transition to DER specific network and retail tariffs	Residential customers in the SWIS are predominantly on a flat A1 tariff, although other time of use retail tariff options such as the midday saver are available for customers to opt-in to.[150] As demonstrated by the CBA modelling, time-of-use tariffs are beneficial to customers joining the VPP with DESS, with controlling of DESS enabling energy consumption to align with off-peak periods, where the price is lower compared to peak periods. The benefits of time-of-use tariffs could also be made available to customers without DESS by enabling access to Community energy storage programs.[151] The implementation of a tariff pilot program to explore tariff structures that encourage system efficient use and investment in DER was a key recommendation in the DER Roadmap (action 17). Importantly, any changes to retail tariff structure and offerings will need to ensure that vulnerable customers are not unduly penalised for not having access to the benefits of DER. The introduction and transition to DER specific network and retail tariffs have a number of potential advantages. This includes providing a financial incentive to DER customers to reward a change in behaviour, shifting energy consumption from peak to off-peak (via time-of-use tariffs),

[147] Ernst & Young, 2023a. *A new form of housing supply for Australia: Build to Rent housing*
[148] Australian Bureau of Statistics, 2022
[149] ARENA, 2020. Social housing added to the Tesla virtual power plant.
[150] Synergy, 2023d. *Midday Saver Pilot*
[151] Synergy, 2023e. *Community battery storage trials*

Initiative	Description
	assisting in alleviating peak demand. They also improve the business case for investments in flexible DER capabilities, such as battery storage and electric vehicle-to-grid capabilities (via time-of-export tariffs), discussed in section 6.6. Some identified risks associated with time of use tariffs include the unintentional consequence of creating a second peak, whereby a large number of customers respond to a price signal resulting in a shift of consumption that creates another peak load or minimum load. If this were to occur, it could potentially result in shifting of prices, with market prices changing to reflect the balance of supply and demand, reducing the value to be gained. However, it is further noted that this assumes that there is a correlation between price and a change of behaviour, and whilst this may hold true for some customers, customer demographics that are not as sensitive to price changes may not change their behaviour where the reward does not outweigh the effort required.

Table 38: Initiatives to increase customer participation in a VPP

It is recommended that further analysis should be completed to determine the applicability of these options in the WEM, as well as to identify additional alternatives to incentivising VPP participation.

6.3 Transition to dynamic connection agreements and enhanced use of DOEs

Dynamic connection agreements are connection contracts that allow for import and export limits at a connection point to be changed dynamically based on the state of the network at a particular time and location, whereby DER owners agree to an alternative to existing connection contracts that set a fixed static limit at the time of connection. As DPV systems increase in size and capacity, dynamic connection agreements provide customers with the ability to install larger capacity DPV systems, enabling them to self-generate and self-consume or export excess generation to the network at most times of the year, provided they are able to receive a DOE from the DSO to reduce the export limit of the customer's DPV. Dynamic connection agreements and DOEs provide a legal and operational framework that ensure that DER assets can be safely connected at a network connection point, maximising the return on value of DER whilst operating within the boundaries of the local distribution network.

In the absence of dynamic connection agreements and DOEs, DPV connections to the Western Power network are currently assigned a fixed export limit shown in Table 39.

Connection Type	Export Limit
Single-phase Connection	5kW
Three-phase Connection	1.5kW

Table 39: Connection limits of DPV inverters for connection types[152]

With most residential customers connected via a single-phase connection, the largest DPV system that is typically allowed to be installed is 5kVA per phase. The limits aim to manage available capacity during minimum demand conditions, however, with these situations only occurring between 1-5% of the year, DPV is usually unnecessarily restricted. The introduction of the ESM function in February 2022 imposed further export limits in an emergency, such as an MDT event, whereby new or upgraded DPV installed in the SWIS with an inverter capacity 5kVA or less must have the capability to be remotely turned down or off during an emergency event in the network. Systems larger than 5kVA will have an export limit of 1.5kW.

[152] Western Power, 2023d. Inverter system with capacity up to 30kVA | Western Power (accessed 26 April 2023)

Though testing the technical feasibility of issuing DOEs was part of Project Symphony, the Pilot only considered the use of DOEs within current network access constraints. As discussed in section 5.1.8, this meant only 5kW DPV systems were modelled in the CBA, which, coupled with the static 5kW export limit applied in the base case, did not adequately demonstrate the potential value DOEs in the orchestration test scenarios, nor specifically the impact of connecting larger DPV systems. Sensitivity analysis was subsequently undertaken, also in section 5.1.8, to model the impact of larger 10kW DPV systems being connected to the network and variations to DOEs. This analysis reveals the true potential of DOEs within the network, allowing a significant increase in DPV exports whilst also managing localised constraints to minimise issues in the network. However, whilst the Pilot successfully tested the use of DOEs to constrain DPV, further testing should be undertaken to monitor the compliance of larger DPV systems in response to DOEs that enable exports to be maximised when there is available network capacity and reduce exports in line with emerging constraints.

DOEs are complementary to dynamic connection agreements and DNSPs in the NEM are already undertaking trials or offering new products to customers that enable flexible export limits.[153, 154, 155] One key difference between the WEM and the NEM, however, is that some DNSPs in the NEM have the ability to enter into these agreements with customers directly. The benefit of this is it captures customers who may not want to enrol their assets in a VPP, enabling DOEs to be applied to more customer DPV assets than if only controlled by the aggregator. As such, it enhances management of the network further and provides additional value outside the aggregator model. Additionally, it may serve as a possible step to VPP participation, with customers able to experience how DOEs impact their systems before deciding to join a VPP. However, this would require significant development of the DSO Platform developed in Project Symphony to enable DOEs to be sent direct to customer DPV and subsequently controlled.

In recognition of the potential for DOEs to enable larger systems in the network and the value larger DPV potentially provides, it is recommended that additional testing be conducted to assess compliance of larger DPV systems with DOEs. Regarding dynamic connection agreements, it is recommended that further investigation be undertaken to determine if dynamic connection agreements should be implemented in the WEM and whether the dynamic import and export limits can be covered by existing bi-directional reference services defined in the Electricity Transfer Access Contract (ETAC), or if a new reference or non-reference service will need to be developed. It is further recommended that Western Power's *Basic Embedded Generation Technical Requirements* document be updated to include consideration of DOEs, in addition to the existing export limits at the connection point for large and small networks.

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[153] SA Power Networks, 2022a. Important changes to SA Dynamic Export Regulation affecting inverter sales and installation (sapowernetworks.com.au)
[154] Solar Victoria, 2023. New Notice to Market to support growing demand for solar (solar.vic.gov.au)
[155] Energex, 2023. Dynamic Connections for energy exports | Energex

SA Power Networks Flexible Exports for Solar PV Project

Project Overview

Flexible Exports is a solar export option that has been developed by SA Power Networks in collaboration with AusNET Services, Fronius, SMA, SolarEdge, and SwitchDin,. The project sought to increase the total capacity of rooftop PV integrated in the NEM by providing a new flexible option to customers that enables their DPV systems to export electricity back into the network, only reducing export during periods when the network is constrained, rather than having static zero or near-zero export limits placed on them. Flexible exports is progressively being rolled out as a standard connection option, with customer able to to opt-out and install solar systems with a fixed export limit of 1.5kW per phase

Key Findings

The most recent report outlines a significant increase in export capacity in the network. The benefits include:

- An additional 44MWh of electricity exported to the network across 77 systems.
- Larger systems realised greater benefit, with a flexible limit of up to 10kW 100% of the time, with this expected to decrease to 98% of the time during seasonal congestion periods.
- Compared to the static export limit, 5kW inverters experienced a 89% increase in exported electricity, with 8.2kW inverters experiencing a 170% increase.
- Compared to the business rule of 5kW export limit, 5kW inverters realised 66% of the maximum, 8.2kW inverters realised 83%, and 10kW inverters realised 98%.

Applicability to the WEM

The use of DOEs to provide time-varying flexible export limits, constraining residential DPV systems, will increase the hosting capacity on LV networks. With 10kW inverters realising 98% of current 5kW export limits during the three month period, allowing 10kW inverters to connect to the WEM on LV networks will only result in networks operating outside of safe operating limits during specific low demand, high solar generation periods. As such, the use of DOEs will ensure safe operating limits are maintained on networks during those times, removing the need for the static 5kW inverter size constraint.

Additionally, by allowing 10kW inverters to connect to LV networks, renewable generation is increased and the value generated for customers is maximised, due to the increase in capacity available to be used for WEM services by aggregators.

Case Study 1: SA Power Networks Flexible Exports for Solar DPV project[156]

[156] SA Power Networks, 2022b. *Flexible Exports for Solar PV: Lessons learnt report 4*

Advanced VPP Grid Integration

Project Overview

The Advanced VPP Grid Integration project, implemented by SA Power Networks in partnership with Tesla and CSIRO from 2019 to 2021 in South Australia, aimed to determine whether DOEs would enable a VPP to export twice the electricity compared to static operating envelopes in the NEM.

To do this, the project developed an Application Programming Interface (API), allowing data to be uploaded from a model forecasting the available hosting capacity of a LV network on a 24-hour rolling basis for each five-minute interval.

Key Findings

Overall, DOEs enabled export capacity to increase, with specific findings as follows:

- The average export capacity during winter months reached 8kW/site (60% increase), with summer and spring months seeing export capacity reach 6kW/site (20% increase).
- Sites aggregated under a VPP were near 100% compliant when considering the average readings, indicating a VPP's capability in adhering to five-minute limits during normal operation.
- Additional export capacity enables use of VPP for frequency control ESS, with one site peaking at 7.8kW.
- Dynamic export limits of 10kV resulted in a material increase in the NPV of a 1,000 customer VPP compared to a 5kV limit when the VPP had access to ESS markets.

Applicability to the WEM

The benefit of increasing to a 10kW DPV system is insignificant when used solely for energy arbitrage in the NEM, with most of the value generated via ESS markets. As the WEM has limited energy arbitrage opportunities, the value of increasing the inverter size limit needed to come from markets outside energy sales. As such, there is material benefit to increasing inverter size limits to 10kW in the WEM, with potentially greater benefit arising if systems can access the RCM.

Also, the WEM is characterised with ample sunlight, allowing for significant increases in capacity to be used in various markets from increasing to a 10kW limit. The issue is compliance of these systems, ensuring system safety and stability. With near 100% compliance, the project suggests inverter limits can be increased safely in the WEM by using DOEs.

Case Study 2: Advanced VPP Grid Integration project[157]

[157] SA Power Networks, 2021. *Advanced VPP Grid Integration: Knowledge Sharing Report*

6.4 Reducing capital and operating costs

The capital and operating costs incurred during the Pilot were predominately related to the cost of developing the DMO, DSO and aggregator platforms, procurement of DER orchestration hardware, and the execution of the test and learn and reporting activities outlined within the Test plan, referred to in section 3.5. In the CBA, these costs are treated as a one-off capital expenditure incurred in the first year of the modelling period.

Through the Pilot, Western Power, AEMO and Synergy have improved their understanding of the resources and capabilities required to establish their business models and operationalise the functionality of the DSO, DMO and aggregator respectively, and it is acknowledged that the functional requirements of these actors will continue to evolve over time. Following the conclusion of the Pilot, it is expected there will be ongoing costs associated with the continuation of DER orchestration activities. A forecast of these costs was provided by Western Power, AEMO, and Synergy, with Synergy providing a forecast of costs for TPAs, estimating the cost to scale the delivery of a VPP over a 10-year period to other parts of the SWIS. The forecast is provided in

		Forecast 10-year capex and opex costs *($M)*
Synergy	Capex	10
	Opex	683
Western Power	Capex	1,280
	Opex	88
AEMO	Capex	19
	Opex	2
TPAs	Capex	-
	Opex	167

Table 40: Forecast 10-year capex and opex costs

The net benefits of DER orchestration are also expected to improve as the capital and operating costs incurred by all parties reduces through reduced technology costs[158] and the maturation of operational capabilities, and as increasing consumer awareness of DER orchestration benefits leads to increased VPP participation.

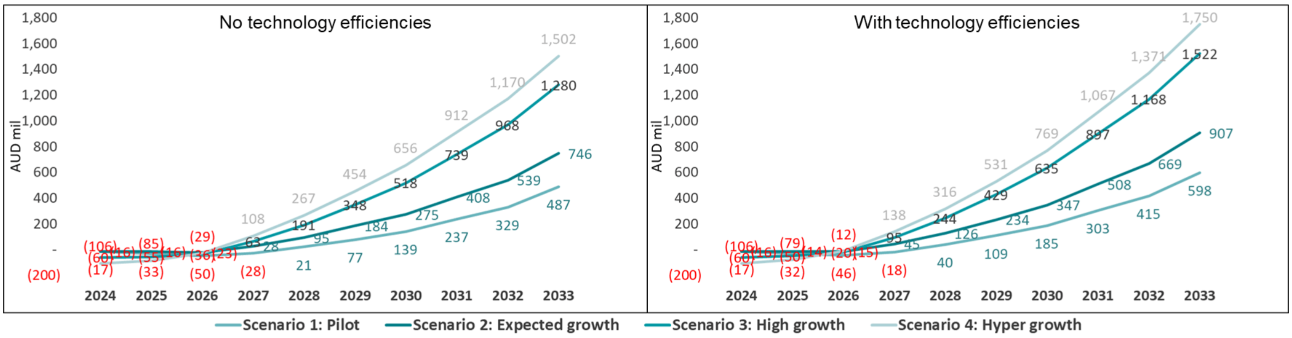
Identifying opportunities to reduce capital and operating costs will contribute to an improvement in the NPV, and whilst it is expected that some of these cost savings will be achieved through economies of scale as the VPP is scaled across the SWIS, key learning outcomes from the Pilot will need to be considered when implementing the VPP at scale.

DER orchestration hardware

During the Pilot, approximately $2.5 million was spent on the purchase and installation of DER communications hardware required to enable communications between customer DER devices, the aggregator, and DMO, equating to a cost of $7,361 per customer. During the Pilot, site visits and ongoing customer support contributed to 80% of the reported installation costs. These costs are not expected to be incurred when the VPP is delivered at scale to the rest of SWIS, with operational efficiencies from maturation

[158] The modelling assumes a reduction in the cost of DESS over 10 years as per the *GenCost 2022-23 report*

decreasing the number of these required. It is futher assumed that the cost of communications devices, such as gateway devices and droplets, will also be borne by the customer. In addition to operational efficiencies, technological efficiencies from maturation are also expected to decrease the cost of the communications devices, reducing the burden placed on customers. Though not included in the CBA modelling, sensitivity analysis considered the impact of technological efficiencies resulting in the cost of communications devices reducing at the same rate as the reduction in the cost of DESS identified in section 4.4. Figure 70 compares the combined yearly undiscounted cashflows in the Fully Orchestrated test scenario when considering technology efficiencies across all modelling scenarios with those when technology efficiencies are ignored:



Pilot **NPV:** $280m
Expected growth **NPV:** $450m
High growth **NPV:** $777m
Hyper growth **NPV:** $920m

Pilot **NPV:** $349m
Expected growth **NPV:** $551m
High growth **NPV:** $931m
Hyper growth **NPV:** $1076m

Figure 70: Combined yearly undiscounted cashflows for the Fully Orchestrated test scenario with and without technology efficiencies

As shown, if technology efficiencies lead to a reduction in communications devices' costs at the same rate as DESS, orchestration via a VPP is likely to deliver between an additional $69 million in the *Pilot* modelling scenario to $156 million in the *Hyper growth* modelling scenario. With the cost of these devices attributed to customers, this additional value is the value passed onto customers. However, a noted risk of passing the cost of communications devices onto customers is it may result in undecided or price sensitive customers declining to participate in the VPP. This risk can be managed by enabling customers to provide their own gateway device (e.g. router), however, this then introduces a secondary risk of interoperability issues where communication between the router and DER is impaired. As industry improves standardisation of communications protocols and Original Equipment Manufacturers (OEMs) embed communication capabilities in their DER devices, it is envisaged this risk will be mitigated.

Whilst the aggregator may choose to retain the cost of providing the gateway devices and droplets, they will need to determine how the cost of these devices are recovered when determining any incentive payments or recruitment costs paid to the customer. It is therefore recommended that the development of the commercial model to engage customers shoud consider the cost of provisioning communications devices or the value of subsidising the cost of these devices in areas of the network where targeted VPP participation is required.

The cost of purchasing and installing high speed data recorders (HSDR) and SIM cards, used to collect data to assess and verify the quality and quantitify of an ESS-CRR response, in the Pilot was $197,000 across 69 sites. HSDRs are a requirement of AEMO's essential system services[159] and Synergy identified this cost as being on a per substation basis, with the Pilot focused on customers connected to the Southern River zone substation. Additionally, Western Power identified each zone substation as having sufficient capacity to serve 50,000 customers, resulting in HSDRs costing approximately $4 per customer. However, it is unlikely that when the VPP is scaled across the SWIS, customer recruitment would organically occur concentrated on zone substation areas, meaning that without targeted recruitment, Synergy could be required to pay

[159] AEMO 2021, WEM Procedure: Communications and Control Systems (aemo.com.au)

$197,000 for 20,000 customers or less. As such, it is recommended that customer recruitment takes an initial phased approach, targeting customers connected to specific zone substations to ensure efficient investment in HSDRs without slowing implementation of a VPP.

Furthermore, it is understood that the the project partners are investigating the suitability of low speed recording devices or revenue grade meters that are capable of collecting data without impacting service compliance. Though an initial phased recruitment approach is recommended to provide rapid roll out of a VPP, the consideration of alternative methodologies to collect measurement data or deploying a fleet of measurement devices that can be moved to different connections points as required, should be progressed as this will contribute to a reduction in cost. If Synergy, or any other VPP facility is able to provide assurance of compliance of its VPP so that it can move to regular compliance checks rather than continuous monitoring, and if able to establish appropriate arrangements with Western Power and AEMO, utilising recorders capable of moving to various substations and significantly decrease the required investment in HSDRs. Any change or deviation from the *Communications and Control System* requirements in the WEM would however require approval from AEMO.

Generation investment and operating costs

The scope of the CBA and DCF analysis focused on Synergy's role as an aggregator and retailer for residential customers. Whilst the total cost of running Synergy's generation business was not considered in the DCF analysis, approximate generation costs were included in the DCF analysis, and it is noted that there is potential to achieve generation capex and opex savings through DER orchestration. This is also expected to deliver economic benefits to the whole of the electricity system and electricity consumers in general, as discussed in work package 2.1.

To determine an indicative estimate of generation investment avoidance or deferral, the annualised growth rate for operational demand and an annualised growth rate for generation capacity in the SWIS was used. If the respective test and modelling scenarios showed peak demand growth could not be met by existing generation capacity or energy injected into the system by the VPP, or a shift in demand behaviour, a cost for the build-out of generation, relevant to the shortfall in capacity size and type of generation facility required (i.e., solar, wind or gas) would be incurred. As a general rule, a shortfall of 100MW in capacity would be met by an investment in 500MW of generation capacity. The build-out costs for solar and wind generation facilities were used to reflect the WA Government's commitment to decarbonisation and the focus on increasing renewable generation in the SWIS. In acknowledging the variability of renewable generation, the build-out costs of flexible gas generators were also considered. The estimated capital expenditure in generation and subsequent maintenance and operation costs were derived from CSIRO's *GenCost 2022-23* report.[160]

In 2021-2022, Synergy reported expenditure of approximately $911 million on *fuel, electricity, gas and other purchases*, however this cost does not delineate the cost of residential or commercial energy, and incorporates costs associated with the generation of both electricity and gas. To estimate the potential cost savings that could be delivered by DER orchestration, a methodology was proposed by the project partners to use the short run marginal cost of generation that would be activated during peak demand periods, and the short run marginal benefit of large-scale generation certificates (LGC) from the use of windfarms during times where the balancing price is mildly negative.

The short-run marginal cost was assumed to be AEMO's mean maximum STEM price ($238.91/MWh) for Synergy's Pinjar Gas generation units, which supplied 41GWh of peak generation capacity in 2019 at a cost

[160] Graham, *et al.*, 2022

of approximately $9.9 million.[161] Using the year-on-year peak demand growth across the 10-year modelling period, the capacity of batteries orchestrated under the VPP could be used to reduce the energy required from marginal generation units. The benefit of LGCs was calculated by identifying intervals with a mildly negative balancing price (between zero and the cost of the RT1 network tariff on a per MWh basis), determining an average price, and multiplying that price by the total solar export curtailed during these intervals. The LGC benefit was calculated to be approximately $2 million across the four test scenarios by the end of the modelling period.

An additional generation cost includes the cost of sustaining coal-fired power plants during intervals where the balancing price is deeply negative. Due to the deeply negative prices, most generation plants would be switched off so to not be exposed to the cost of selling at those negative prices. However, the cost of turning coal-fired power plants off and then starting them up again outweigh the cost of sustaining their power during these intervals. Due to a VPP assisting in flattening demand curves, it is expected that the price smoothing arising from DER orchestration would provide additional cost savings in this area as well. However, any quantification of these costs and resulting cost savings requires in-depth whole-of-system market modelling that falls outside the scope of this CBA. As such, further analysis in this area is recommended.

Although assessing the Synergy's generation business was not considered within the scope of the CBA, it is acknowledged that DER orchestration delivers significant benefits to achieve decarbonisation ambitions, that and should be further considered in future workstreams.

The CBA reports the anticipated CO_2 emissions that can result from an increase in generation as per the generation energy mix that was applied. Gas peaking plants were envisioned as part of capacity increases to support renewables that were the main source of generation. Specifically, for every 100MW of generation requirement the following generation mix was applied:[162]

New power stations (additional capacity)	% of total capacity
Solar capacity	56.5 %
Wind (onshore) capacity	35.0 %
Gas capacity	8.5 %
Coal	0.0 %
Total	**100%**

Table 41: GenCost 2022 Generation mix[163]

The CO_2 generation per MWh applied is as follows:

CO2 per MWh of generation	
CO_2 (in tons) per MWh of Gas generation	0.39 tons / MWh
CO_2 (in tons) per MWh of Coal generation	0.89 tons / MWh
Cost of CO_2 generated per ton	$35 (AUD) / ton

The figures were selected by taking the minimum CO_2 emissions from existing generators on the basis that any new facilities would be as efficient as the most efficient current generator. As for the cost per CO_2 a $35

[161] Marsden Jacob Associates, 2020. *2020-21 Energy Price Limits Review – Final Report*
[162] Note: The model can cater for Coal, but this was not considered as part of the future generation mix.
[163] Graham *et al.*, 2022

per ton was applied across all years which is a conservative estimate. The cost was applied for all CO_2 since this is viewed as a cost to society even though the actual cost would be determined under the safeguard mechanism.

Under the Fully Orchestrated scenario, the potential NPV of carbon credits provides a benefit of $23 million over 10 years, in the *Expected growth* modelling scenario. Further information on DER orchestration can support greenhouse gas emissions reduction is provided in section 6.7.

It is recommended that benefits of DER orchestration and potential to participate in electricity markets such as the RCM, discussed further in section 6.5, should be investigated further and integrated into Synergy's generation and transition planning activities.

Transmission and distribution network investment

WA's shift to a clean energy future will require continued investment in the transmission and distribution networks to increase capacity and maintain reliability associated with increased demand, industrial electrification, and the bi-directional flow of electricity.

With the SWIS Demand Assessment resulting in the connection of 50GW of generation and storage capacity by 2042, there will be a significant impact on the availability of resources across the energy sector, and result in significant investment in the transmission and distribution networks. The strategic and financial benefits of network augmentation deferral that can be delivered through DER orchestration will become more important to ensure that Western Power can redirect its available resources to deliver the transformation changes to the network proposed in the SWISDA, whereby the WA Government has committed an additional $120 million to Western Power to deliver stage 1 of network investments.

Significant network investments have already been identified by Western Power and are already in the planning phase to be delivered over the next 10-years. These investments will alleviate some of the existing network constraints, at both transmission and distribution levels, caused by localised voltage or thermal constraints. However, there are significant parts of the network that will require augmentation soon, as increases in energy demand provide further loading constraints on the network, compounded by increased DER penetration and an aging network.

As discussed in section 5.1.4, there are tangible capex savings or deferral that could be provided by NSS, where there is sufficient localised capacity within the VPP that can be called upon to provide NSS and to relieve localised network constraints. Logistically, enrolling sufficient capacity of DER such as DESS and other controllable DER loads in the same geographical area may be problematic. However, commercial sized DESS and grid connected community battery storage provide a practical solution in the short term to achieve the required volume of energy storage or controllable loads for NSS, whilst waiting for BTM DESS numbers to increase to a sufficient scale. As mentioned, the Pilot included a grid connected battery and commercial DESS in the later stages of the stability period. Though not statistically significant to include in the CBA modelling, testing of these larger assets revealed much greater capabilities to provide both NSS and ESS-CRR compared to BTM DESS. It is noted, however, that larger commercial DESS require a different connection agreement and approval process compared to BTM residential batteries and will require Western Power to have sufficient capacity and capability to expedite the connection process, which according to the ESOO growth forecasts for residential and commercial battery connections, is likely to experience significant strain with a large number of customer connection applications expected over the next 2-3 years.

To assist in ensuring adequate capacity of DER is available for NSS, it is recommended that Western Power should continue to monitor the impact of DER penetration on the network and complete any required power system studies to identify specific areas of the network that would benefit from DER orchestration. These studies will contribute to the development of the Network Opportunities Map and 10-year transmission plan, identifying opportunities for VPPs to invest in building NCESS capacity, and to provide additional justification for investment that may be required for final investment decisions.

6.5 Accessing the value of DER in other energy services and markets

A key element of any electricity system is the real-time balancing of supply and demand. Historically, demand (load) has been relatively easy to predict as customers sourced their electricity from the grid, and supply (generation) was firm and could be dispatched to match real-time demand.

Globally, two trends are occurring concurrently that make the balancing of electricity systems more challenging:

- Decarbonisation: replacement of thermal generation with weather-dependent (and hence variable) renewable sources of generation, and
- Decentralisation: customers increasingly installing technologies such as DPV and DESS to take control of their own electricity needs.

In this environment, managing the supply-demand balance and ensuring availability of sufficient ESS, such as frequency and voltage control, is more challenging.

Project Symphony demonstrated orchestrated DER can provide system, network and market services. Whilst customers will continue to adopt DER to reduce their reliance on the grid and their energy bills, the potential of DER can be harnessed to not only meet the needs of DER owners, but also increase the efficiency and effectiveness of the energy system, reducing costs for all consumers irrespective of whether they own DER, by:

- Reducing the cost of wholesale electricity.
- Reducing the cost of ancillary services.
- Deferral or avoidance of generation expenditure.
- Deferral or avoidance of network expenditure.

Project Symphony took an important step to demonstrate the capability of a VPP aggregating DER connected to the network to generate and store electricity at a local network level to provide a limited scope of market, system, and network services. However, the integration of DER in existing markets, and development of new energy markets, has the potential to deliver significant value pools, particularly where there is already a high penetration of DPV and high expected growth of residential and commercial DESS. Figure 71 provides an illustration of the potential value pools where DER can provide value to the system and market operator, network operators, generators and retailers, and the end consumer.

The teal-coloured line in Figure 71 provides an illustration of the value pools tested in Project Symphony and this CBA compared to the other potential value pools that could be supported by a VPP.[164]

[164] Provided for illustrative purposes only. Further analysis is recommended to quantify the value of revenue streams that were outside the scope of the Pilot and CBA

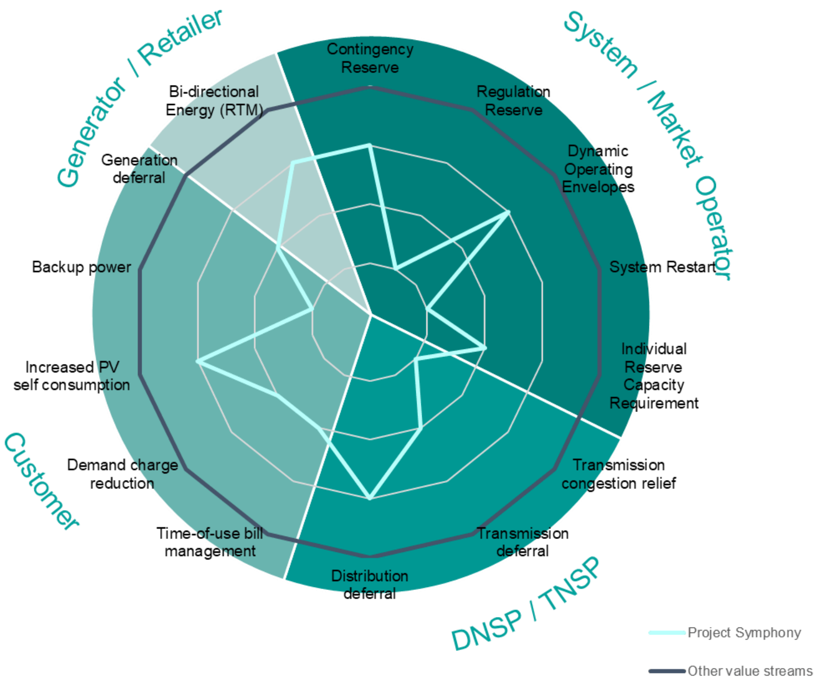


Figure 71: Value pools of DER orchestration

The continued evolution of regulatory frameworks, including market design and technical rules and maturation of DER orchestration roles and responsibilities, will be critical to ensure that the full value of DER can be achieved, examples of which are outlined in the table below.

Progress market and regulatory reforms	Electricity markets and regulatory frameworks are typically designed for the long-term interests of consumers. However, most frameworks were designed for centralised electricity systems before significant volumes of distributed assets existed. The high penetration of DPV and forecast adoption of other DER assets (e.g., DESS and EV) in the SWIS will require changes to regulatory frameworks to accommodate DER participation and remove barriers to DER delivering the full range of electricity services, where it can be demonstrated that DER can provide market and network services at a lower cost than network and generation investments.
Standardise DER communication standards and interoperability requirements	Different technologies operate under different technical/asset standards, and even within technology types, different manufacturers use separate communication standards or proprietary communication protocols. Aggregators gain competitive advantage through integrating many different types of devices into their control software, often using a proprietary 'gateway' device, such as the SwitchDin Droplet.[165] 'Software only' aggregators, however, are also becoming more prominent and focus on integrating with the OEMs' cloud control system, for example, Enode[166] or Evergen.[167] Effective integration of devices into aggregator control platforms creates a competitive advantage,

[165] SwitchDin
[166] Enode: Energy APIs for EVs, Thermostats and DR
[167] Virtual Power Plant (VPP) Software Company | VPP Platform | Evergen Energy

	and potentially limits customer switching and choice. DER orchestration (at scale) and support of multiple aggregators would be simplified by standardising how to communicate and control different types of DER through: • Communication protocols – i.e., the language that each device communicates in. • Technical capabilities – devices are made with consistent demand response capabilities Project EDGE demonstrated the potential benefits of establishing an industry data hub to harness interoperability patterns and protocols are implemented consistently for all participants. A review of the most common international communication protocols for DER (including, but not limited to, IEEE 2030.5, IEC 61850, and ISO 15118 etc) would be beneficial to determine the appropriate communications and interoperability standards for the SWIS
DER coordination and management systems	Project Symphony developed three separate platforms that were integrated to enable the end-to-end flow of data between project participants and operationally manage DER across multiple connection points, including: • Communicating network limits or dispatch instructions to aggregators, and to integrate DER coordination within the broader network operations functions. • Orchestrating DER to deliver electricity services to the market and network. • Establishing a baseline to explore opportunities to maximise the return-on-investment of project participants, whilst balancing the impacts on others. Continued development of Web3 technologies and convergence of artificial intelligence (AI), blockchain technology, edge computing and IoT technologies will support further development of DERMS, delivering improved efficiency and productivity and more targeted customer experiences.[168]

It is recommended that further testing and analysis should be completed to determine the value of DER orchestration in providing the energy services that were not included in the scope of the Pilot and CBA modelling, and to identify any technical, regulatory or commercial barriers that will need to be overcome.

6.5.1 Essential System Service – Contingency Reserve Lower

Contingency Reserve Lower, like Contingency Reserve Raise, addresses contingency events that cause frequency in the system to move outside of the normal operating band. However, whereas Contingency Reserve Raise seeks to raise frequency, Contingency Reserve Lower seeks to decrease the frequency in the system by either rapidly constraining export of electricity from generators or rapidly increasing import from loads, as shown in Figure 72. This is to address contingency events that cause significant spikes in frequency, such as a sudden surge of generation or the loss of a load.

[168] MIT Technology Review Insights, 2022. Accelerating the energy transition with Web3 technologies | MIT Technology Review

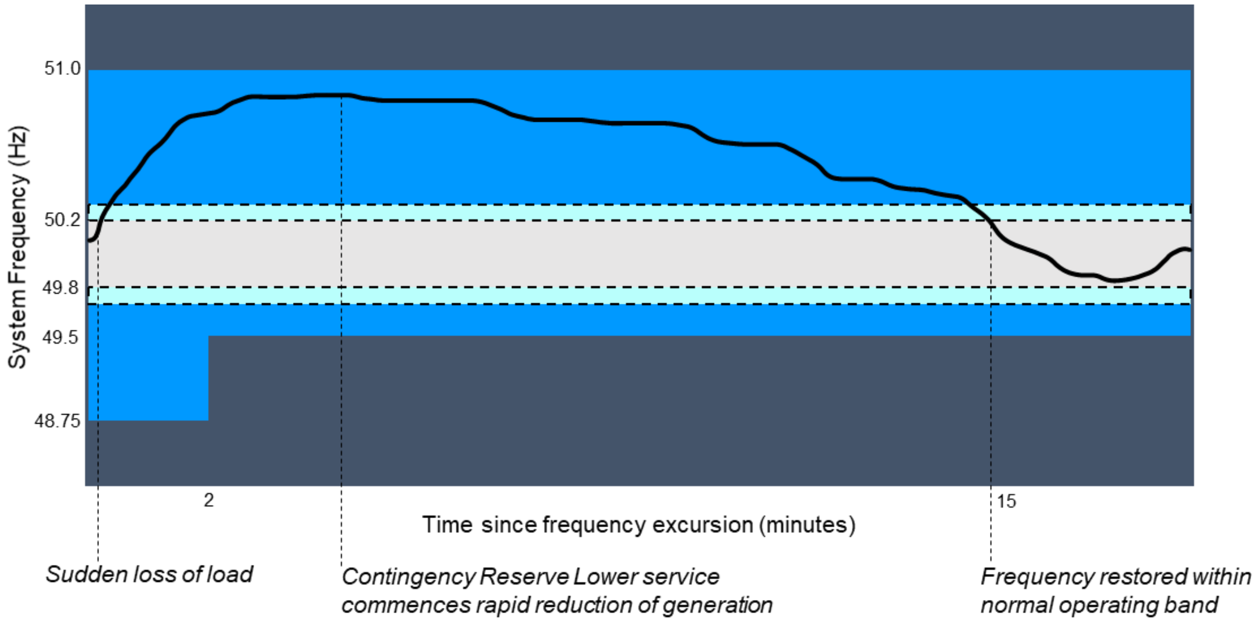


Figure 72: Restoring frequency using Contingency Reserve Lower service

As such, to demonstrate Project Symphony's solution's capability in delivering the full suite of frequency control ESS, additional testing should occur to explore the capability and value of DER orchestration for Contingency Reserve Lower services. The successful use of the three platforms developed in orchestrating DER under a VPP to provide Contingency Reserve Raise provides the necessary insight into demonstrating capabilities in providing Contingency Reserve Lower.

Though DER orchestration successfully demonstrated the capability to provide Contingency Reserve Raise, it should not be assumed it can also provide Contingency Reserve Lower. This is due to Contingency Reserve Lower requiring DER to be managed in the opposite manner. Rather, the learnings need to be integrated into the solution and aggregated DER demonstrated in additional testing as having the required capabilities, either decreasing the generation of electricity from DPV systems, or holding loads such as battery storage systems and electric hot water systems in reserve to rapidly draw electricity out of the system. Further investigation should be undertaken to assess the capability and value of a VPP providing ESS Contingency Raise Lower.

6.5.2 Essential System Service – Regulation Raise and Lower

Regulation Raise and Lower is a market-provided response to automatic generation control signals to correct for small deviations in frequency during a dispatch interval, as shown in Figure 73. However, where contingency events require a fast and strong response, Regulation Raise and Lower occur on a smaller scale, making minor changes to the supply of electricity, balancing it with demand, to account for small deviations in load or generation.

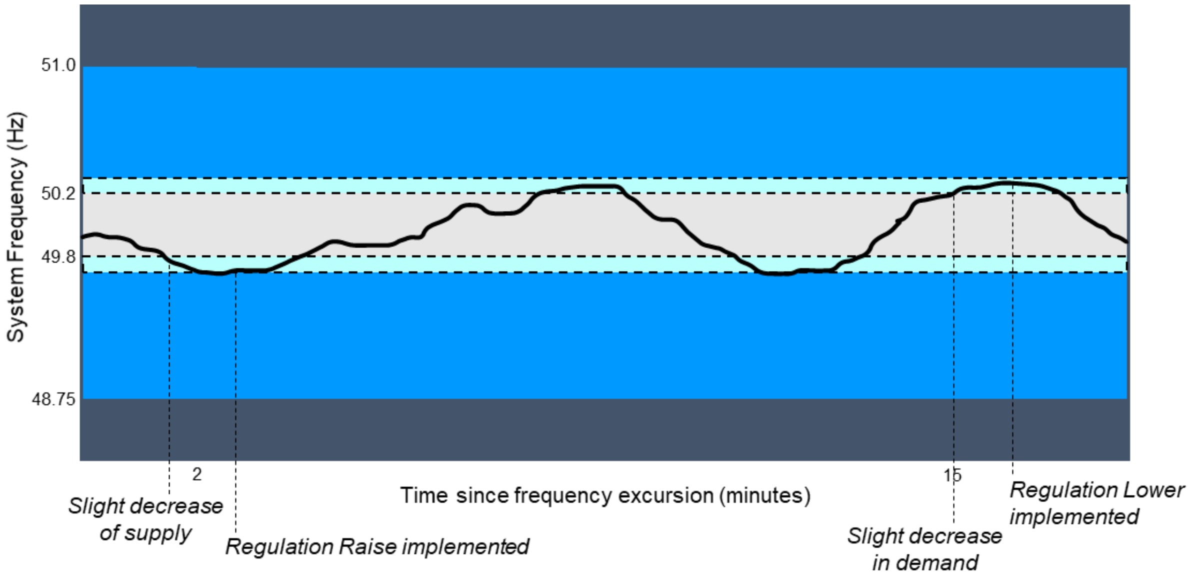


Figure 73: Restoring slight deviations in frequency using Regulation Raise or Lower services

As such, in addition to the Contingency Reserve Lower service outlined above, Project Symphony's solution should undergo further testing to demonstrate orchestrated DER's capabilities in providing the full suite of frequency control ESS. This includes the DMO Platform demonstrating capabilities in coordinating the use of DER to either inject or withdraw generation to ensure continuous balancing of supply and demand. A major difference between Regulation Raise and Lower and Contingency Raise and Lower is the frequency in which it is used. As Regulation Raise and Lower requires continuous balancing, control signals are issued every 4 seconds, requiring high speed SCADA and communications to instruct registered facilities via the aggregator platform to respond and ramp to deliver the maximum quantity of Regulation Raise or Regulation Lower within 5 minutes.[169] Specifically, the Aggregator Platform will need to be able to utilise batteries to hold a certain volume of electricity in reserve, allowing it to either feed electricity back into the system or draw electricity out as required. As such, the capacity of the AEMO Platform and Aggregator Platform to do this effectively would demonstrate the level of integration between them.

Further investigation will be required to overcome the technical and commercial requirements for VPPs to provide Regulation services.

6.5.3 Reserve Capacity Mechanism and demand response

In 2022, Energy Policy WA commenced a periodic review of the RCM[170] with a focus on the planning criterion under which the RCM operates in keeping with changes to energy demand and the market. Whilst changes to the RCM were introduced in October 2023, enabling the participation of energy storage (e.g., DESS), further changes to the RCM will continue to be explored by Energy Policy WA as the State transitions to a high renewable energy future to ensure adequacy and reliability of electricity supply at the most efficient cost for consumers.[171]

Under existing and approved changes to the WEM rules, orchestrated DER are not permitted to provide services to the RCM, such as demand side programs, however information published by Energy Policy WA in August 2023 (at the conclusion of the public consultation period), confirmed that RCM payments would be

[169] AEMO, 2021e. *WEM Procedure: Frequency Co-Optimised Essential System Services Accreditation*
[170] Energy Policy WA, 2022b. *Reserve Capacity Mechanism Review*, "Stage 1 Consultation Paper"
[171] Energy Policy WA, 2023f. *Reserve Capacity Mechanism Review*, "Stage 2 Information Paper"

made available to any Facility assigned a Certified Reserve Capacity (CRC), including a VPP, provided it is able to meet the criteria for registering for the demand side programme.[172]

Globally, demand response programs are playing an increasingly important role in electricity systems and markets. This development is being driven by a need for more flexible and dispatchable resources on both the supply and demand side to accommodate the increasing penetration of variable renewable generation and changing consumer preferences, as well as technological advancements that allow customers to more easily participate as active demand side resources.

A study completed by the Australian Energy Market Commission (AEMC)[173] considered how demand response programs were being implemented across residential, commercial, and industrial sectors. The study found that a variety of DER are being included in demand response portfolios, including air conditioners, hot water systems, DESS, pool pumps, and EVs. The study also found that customers were electing to "opt-in" to participate in demand side programs as opposed to being mandated to participate, with aggregators providing customers with choice over what resources are controlled and the ability to manually override an intended response. Whilst providing customers with additional flexibility and choice on whether or not to be controlled, aggregators often oversubscribed enrolment in demand response programs to manage the risk of not having the capacity to deliver during a demand response event. This was often seen during certain seasons or time of day; or as a result of "response fatigue" where a response may be required more often than expected or required manual intervention as opposed to an automated response. Barriers identified to the uptake of participating in or providing a demand response program included the lack of financial incentive required to entice customers to participate, a lack of understanding or interest in participating in demand response, and the complexity within the existing regulatory framework of providing a scheduled response, similar to generators in the market.

In August 2023, proposed electricity rule changes were submitted by AEMO to the Australian Energy market Commission (AEMC) in the NEM to provide a mechanism for DER participation in flexibility markets.[174] The "Scheduled Lite" mechanism seeks to provide consumers with increased opportunities to maximise the value of their DER, supplementing their ability to earn revenue beyond feed-in tariffs and off-market demand management services. The proposed rule change will enable price-responsive DER to participate in the market scheduling process by establishing a voluntary and flexible participation framework. The potential benefits AEMO identified to DER owners and consumers as a whole included:

- Improved competition.
- Improved choice and innovation available to consumers to utilise their DER resources in the market.
- Access to new revenue streams.
- Reduced need for emergency backstop measures and curtailment of DER by the system operator and regulator.
- Lower overall energy costs to all consumers through increased DER participation in energy and ancillary service markets.
- Signalling the market to encourage longer-term investment in DER orchestration assets and capabilities.

The potential capacity and capability of a VPP to provide RCM and demand response services, where customer DER receive instructions from the VPP to adjust their energy consumption during peak periods when energy prices are high or increase consumption when prices are low, align with capabilities tested in the Pilot, which demonstrated a positive response from the VPP to market instructions. As such, the

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172 Energy Policy WA, 2023f
173 Energy Synapse, 2020. *Demand response in the National Electricity Market: Final Report*
174 AEMO, 2023f. *Electricity Rule Change Proposal*, "Scheduled Lite"

allocation of CRC to accredited VPPs would support additional opportunities to shift demand and load profiles and stimulate third party investment and participation in these schemes due to greater certainty that providers will be financially compensated for these services. Therefore, further consideration of how accredited VPPs could participate within the RCM should be considered.

6.5.4 System Restart Service

A System Restart or System Black Event occurs when there is an absence of voltage on the transmission network following a major disruption to the electricity system and may be caused when there is a sudden or unexpected loss of a large load or generator or minimum demand threshold event.

The impact of a System Black Event results in the complete loss of electricity supply to residential, commercial, and industrial customers, and critical community, emergency, and essential services, including, but not limited to, hospitals, telecommunications, and transport, for an extended period. The impact of a System Black Event on the entire State has the potential for significant impacts to the WA State economy, including a financial impact of $2m per minute/$120m per hour. To put this in perspective, the last System Black Event that occurred in South Australia had a financial impact of ~$367m and took 7.5 hours to restore power to 80-90% of customers.

AEMO is responsible for the preparation and update of operational plans to restart the SWIS in the event of a system shutdown. In accordance with WEM Market Rule 3.7.5, AEMO has a System Restart Plan (SRP), which outlines the actions that AEMO, in coordination with the Network Operator, must take to prepare for the restoration of the power system in the event of a System Black Event. The SRP identifies feasible restart pathways with stable blocks of loads, which are required to start up and load synchronous Black Start generators, and was reviewed in 2020 to incorporate the prioritisation of the restart pathways with low DPV generation. Acknowledging the current SRP approach may no longer be viable without extra capabilities and mechanisms to manage DER behaviour during the restart process, further review is required to consider use cases and recommendations to address the identified challenges, including but not limited to a System Restart Service (SRS).

An SRS is a specific form of NCESS that can be procured by AEMO in the unlikely event of a System Black Event.[175] It is recommended that the potential benefits of leveraging a VPP to provide an SRS should be considered and supporting processes should be developed as part of System Black Event planning and preparedness activities per the requirements of clause 3.7.21 and 3.7.38 of the Wholesale Electricity Market (WEM) Rules.[176]

6.6 Maximising the types of DER assets that can provide orchestration services

As mentioned, the DER assets included in Project Symphony was limited to a subset of DER, with the modelling and CBA focused on assessing the value of orchestrating residential customer DPV and DESS. As such, it is expected that greater value can be generated if orchestration is expanded to include EVs, grid connected batteries, air conditioners, and electric hot water loads. The following provides qualitative assessment with case studies showing how these DER assets can provide additional value.

6.6.1 Electric Vehicles

EV sales are expected to grow rapidly, with sales in Australia having already tripled from 6,885 in 2020 to 20,665 in 2021. By 2030, EVs are expected to be cost-competitive and forecasted to account for 50% of

[175] AEMO, 2023d
[176] *WEM Rules 2023* (WA)

Australian new car purchases,[177] contributing to an additional 2% and 12% of residential consumption (up to 7 TWh). As a response to the global trend of rising EV uptake, the WA Government developed a State Electric Vehicle Strategy in 2020, accompanied by a $21 million investment. To ensure WA is prepared for the growth in EV adoption, part of this investment will be directed towards creation of EV charging infrastructure across the State.[178] Though EVs have seen very slow adoption in WA compared to international jurisdictions, as EV sales grow, they will become a potentially significant resource for the network.[179] AEMO's 2023 WEM ESOO forecasts an expected 2.6TWh of energy consumption per annum by 2032-33,[180] an increase of approximately 50% from the 2022 ESOO forecast, as shown below:

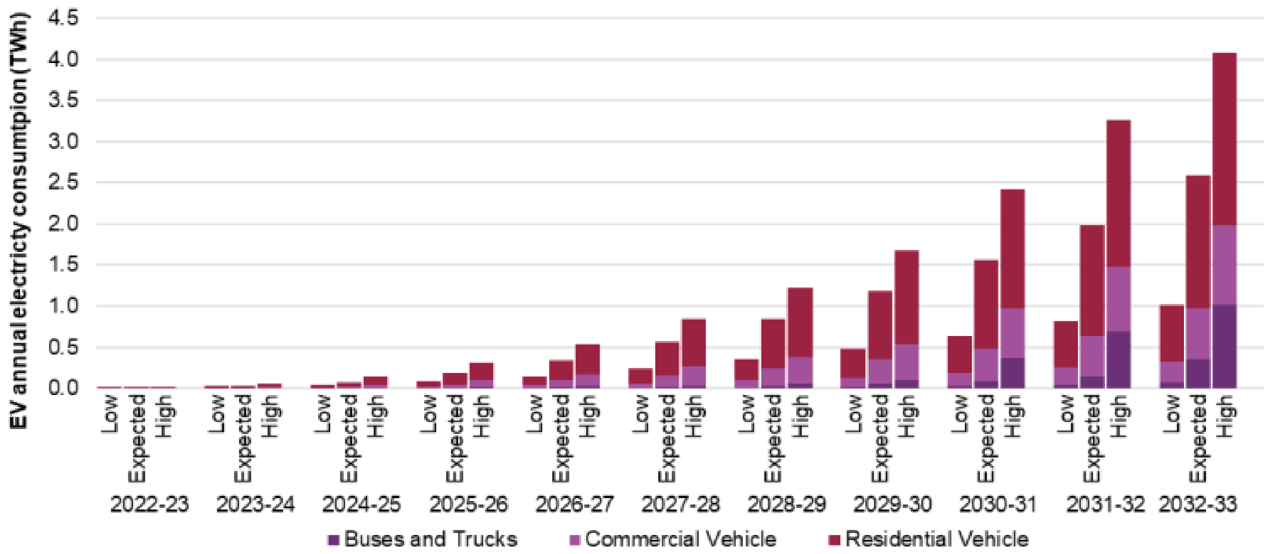

Figure 74: Number of EVs in the SWIS under three demand growth scenarios[181]

This rapid increase means EVs are likely to have a significant impact on the network and future integration of EVs into the grid and the market. To better understand the impact and ensure EVs can be successfully integrated as a DER into a VPP, two use cases relating to EVs in the network have been identified:

- EVs as a controllable load.
- Vehicle-to-Grid (V2G) / vehicle-to-anywhere (V2X).

The growth of EVs is expected to be a major contributor to forecasted increases in demand for electricity with a EV consumption from commercial vehicles and public transport expected to increase from 0.6MWh to 346.8GWh by 2032-33, representing 13.4% of total EV consumption.[182] Though EVs provide numerous benefits in terms of carbon emission reductions and shielding customers from rising petrol prices, the expected increase is expected to significantly contribute to higher peak demand across the network, particularly in areas that are constrained, with EV charging projected to account for 2% to 16% of peak demand depending on the region.[183] Figure 75 provides an overview of this, showing the impact of EVs across different demand profiles.

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[177] Clean Energy Finance Corporation, 2018. *The Australian Electric Vehicle Market*
[178] Department of Water and Environmental Regulation, 2020b. *State Electric Vehicle Strategy for Western Australia*
[179] Energy Transformation Taskforce, 2019a
[180] AEMO, 2023a. p. 32
[181] AEMO, 2023a. p. 32
[182] Electric Vehicle Council, 2022. *State of Electric Vehicles*
[183] AEMO, 2020. *2020 Electricity Statement of Opportunities*

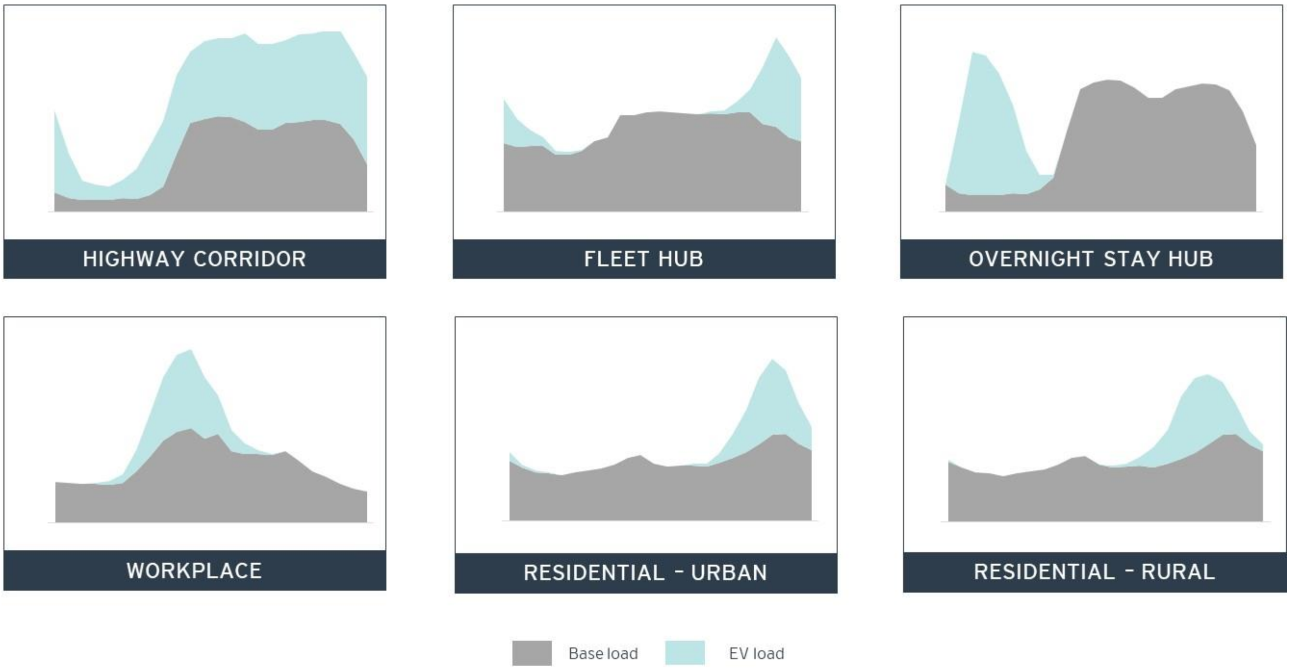

Figure 75: Demand profiles of EVs at different charging locations[184]

By allowing aggregators to include EV charging stations as DER in their portfolio, rather than contributing to peak demand, EVs can be used to flatten demand curves, helping stabilise the electricity system.

The use of EVs as a controllable load will allow aggregators to send signals to EV charging stations with instructions on when to commence charging. In relation to the four test scenarios in Project Symphony, as a type of DER asset, it is important that EVs are able to be dispatched in alignment with DOEs provided by Western Power as the DSO. To assist in minimising NSS required in the network, EVs will need to be controlled to increase or decrease electricity import as required. In this way, EVs can reduce consumption during peak times so to not contribute to peak demand and increase consumption during times of low demand and when DPV generation is high, increasing overall system stability and reliability. Specifically, the use of EVs as a controllable load is expected to decrease curtailment of DPV systems, maximising the value customers gain from DPV. Additionally, by reducing the impact of EVs on peak demand, distribution feeders are less likely to be over-utilised, reducing the volume of NSS required or potential need for network augmentation than if EVs were unorchestrated.[185]

V2G technology takes the use of EVs as controllable loads further by enabling bi-directional flow of electricity from an EV battery, providing greater potential for EVs to be used to smooth demand curves. According to the Race for 2030 report, the total storage capacity of EV batteries in Australia is projected to be between 180 to 360GWh by 2050, providing more capacity than required by residential consumption.[186] However, V2G technology is still immature, with deployment heavily dependent on adoption of smart charging infrastructure in the SWIS and enhanced data visibility. Though V2G is still in its nascency, advancements in technology, infrastructure, and policy change (such as ISO 15118 which provides a standardised method for an EV and the EV Supply Equipment to communicate information that enables authentication, automatic billing, and bi-directional charging) will enable EVs to store excess output from DPV systems and other distributed generators, dispatching electricity back into the SWIS to address times of peak demand and

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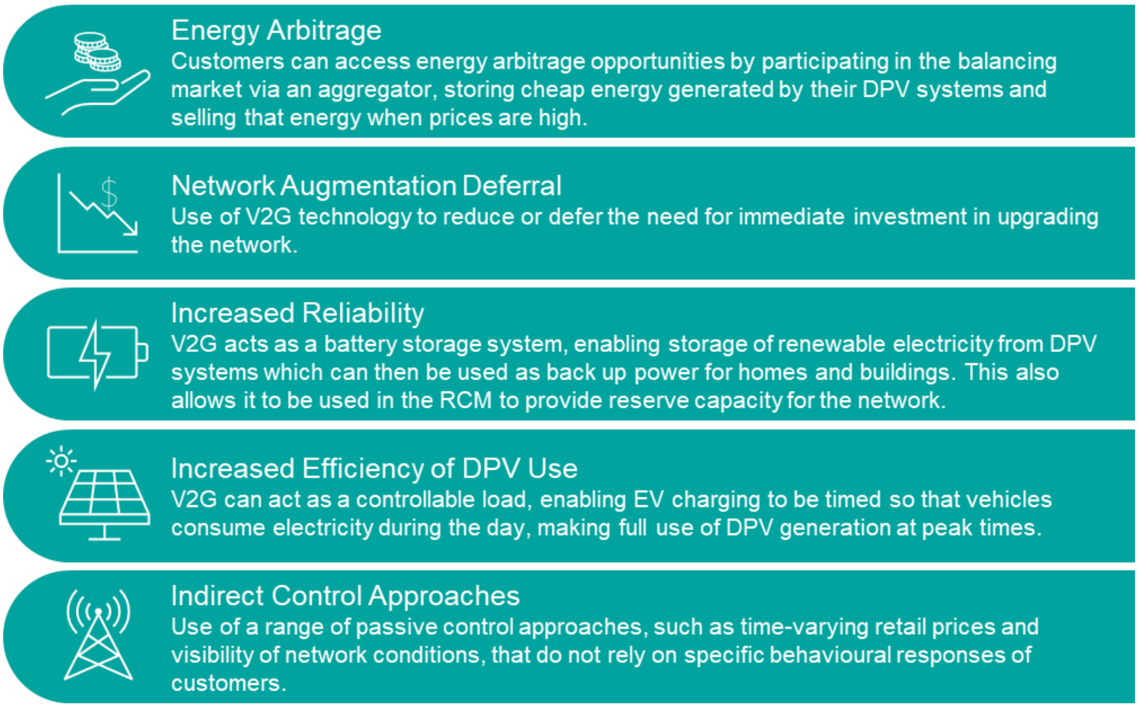
[184] Ernst & Young Analysis, 2023. *WRI EV Simulator*
[185] Electric Vehicle Council, 2022
[186] RACE for 2030, 2021a. *Electric vehicles and the grid*

support system stability. As such, V2G enables EV owners to participate in wholesale demand response mechanisms and provide flexibility services during peak times,[187] with the following applications of V2G technology identified by the Vehicle-Grid Integration (VGI) working group as providing the highest potential value:[188]



Due to the slower uptake of EVs in WA compared to the east coast of Australia, the WEM is in the unique position of being able to take learnings of EV integration and orchestration trials in other electricity networks to prepare for the coming growth of EVs. As such, rather than taking a reactive stance to EVs and the challenges they bring to the network, the WEM can proactively implement reform and changes to the SWIS using evidence-based solutions.

To support an increased uptake of EV, and to optimise EV charging and market integration, a review of international and national insights on EV integration should be considered to develop a consistent set of connection standards and communications protocols for connecting EV charging infrastructure to the network. To support the implementation and adoption of these standards, the connection process for EV charging infrastructure should be streamlined and coupled with the development of EV specific charging tariffs to incentivise investment in EV charging infrastructure in areas of the network deemed by the network operator to provide the most benefit or least cost of network augmentation. It is further recommended that the inclusion of EV charging and EV specific tariff should be included in a future Pilot to validate the benefits of EV capabilities in a VPP.

[187] RACE for 2030, 2021a
[188] California Public Utilities Commission, 2020. *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group*

AGL Electric Vehicle Orchestration Trial

Project Overview

AGL Energy Services implemented their Electric Vehicle Orchestration Trial in November 2020, with the trial expected to finish in February 2024. The trial sought to accelerate the development of EV charging management and orchestration in the NEM to realise benefits for customers and the electricity supply system whilst ensuring impacts on the electricity grid are minimised.

The initial scope of the project included testing of V2G charging, however due to compliance and technical issues, the trial has needed to revise this. AGL has successfully tested orchestration of:

- Residential EV smart charging systems
- Vehicle API charging control

Key Findings

Regarding orchestrated residential EV smart chargers:

- Charging controls are effective in reducing peak demand
- Opt-out rates are very low

Regarding API charging control:

- API provides visibility of vehicle battery and charging data
- There is less charging at home than expected

Despite unable to test V2G technology, the trial found that:

- V2G technology needs significant development for it to become commercially viable, including work relating to standards, technological readiness, and vehicle availability

Applicability to the WEM

EVs can be successfully orchestrated under a VPP as a DER asset through the use of an aggregation platform, similar to the Aggregator Platform developed by Synergy as part of Project Symphony's pilot. As such, it is likely that EVs can be integrated into an aggregator's DER portfolio as a controllable load.

Particularly, EVs can be used to smooth demand curves by controlling import of electricity from EV charging stations, EVs have the potential to provide FCESS, either by decreasing import to raise frequency or increasing import to lower frequency across the network. Similarly, EVs could be used to provide NSS, managing net import of electricity at a local level.

Case Study 3: AGL Electric Orchestration Trial[189]

[189] AGL, 2022. *AGL Electric Vehicle Orchestration Trial: Lessons Learnt Report 3*

Intelligent Electric Vehicle Integration (INVENT) Project

Project Overview

The INVENT Project was a collaboration led by the Nuvve Corporation, implemented at the University of California at San Diego's campus from July 2017 to June 2021, and sought to demonstrate the real-world benefits of advanced V2G Integration applications for EVs and its commercial feasibility, warranting the development of supporting legislation and policy. The trial integrated a total of 50 bi-directional and unidirectional EVs with a third-party intelligent collection and control platform to demonstrate:

- Demand Charge Management (DCM) in connection to electricity retail prices.
- Renewable energy time-shifting to coordinate DPV systems with EV charging.
- Response of EVs to frequency regulation signals from the California ISO via a VPP.
- EVs engaged in aggregated demand response bids via the investor-owned Demand Response Auction Mechanism

Key Findings

The use of EVs in the DCM resulted in an average demand charge savings of US $888 per EV, annually.

EVs were successfully able to participate in the frequency regulation ancillary service market, achieving a performance well above the minimum threshold and on the upper end of the California ISO system average (30-60%) for Regulation Raise and Regulation Lower, resulting in the following benefits:

- Increased network security
- Customers gained access to ancillary services markets via an aggregator

Applicability to the WEM

The Aggregator Platform developed by Synergy can be developed to reflect the INVENT Project's platform, enabling aggregated EVs so to use them as controllable loads.

Bi-directional EV charging stations integrated with V2G technology can enable EV participation in ESS markets. INVENT's focus on Regulation Raise and Lower services demonstrate EVs' being used for fast-reacting frequency control services. As such, EVs are likely able to be used for Contingency Reserve Raise and Lower services, storing energy in their batteries to be dispatched by AEMO.

Case Study 4: INVENT Project[190]

[190] Larcher & Piero, 2021. *Intelligent Vehicle Integration*

FCA-ENGIE Eps Vehicle-to-Grid (V2G) Pilot Project

Project Overview

The V2G Pilot Project is a collaboration between Fiat Chrysler Automobiles and ENGIE Eps to be implemented in Turin, Italy, from 2023 to 2027, and aims to demonstrate the world's first large-scale industrial application of V2G technology integrated with 'second-life' batteries.

Specifically, the V2G Pilot hopes to demonstrate:

- The use of second-life batteries to provide frequency control ESS by focusing on fast frequency regulation services
- The possibility of combining an electrochemical storage system with smart EV charging infrastructure and V2G solutions.

Expected Benefits

As the V2G Pilot Project has not been completed, there are currently no reported benefits. However, the project expects to provide the following value:

- Increased network stability via demand management to optimise timing of EV charging and use of V2G technology to enable electricity to be exported back into the network, improving network reliability.
- Additional access to Regulation ESS, improving system stability and security.
- Reduced cost of EV lifecycles by using second-life batteries, with customers receiving exclusive offers and discounts.
- Additional income or credits for customers to use towards their electricity bills.

Applicability to the WEM

WA's slow EV uptake puts it in a position to watch trials not yet complete, like the V2G Pilot Project, and implement learnings. This project shows the potential of combining V2G technology with second-life batteries to provide frequency control ESS, lowering EVs' overall cost whilst enhancing network reliability. If the V2G Pilot Project is successful, it represents an opportunity to increase EV sales in WA.

EVs have already been demonstrated as capable of providing frequency control ESS via other trials, such as the INVENT Project. However, the V2G Pilot Project will demonstrate whether second-life batteries have the required capabilities in a large-scale industrial application. If successful, it will present an opportunity to use V2G technology on an industrial scale.

Case Study 5: FCA-ENGIE Eps V2G Pilot Project[191, 192]

[191] Fiat, 2020. FCA-ENGIE EPS BEGIN WORK ON VEHICLE-TO-GRID PILOT PROJECT - Fiat Cyprus (accessed 6 April 2023)
[192] Stellantis, 2020. FCA and ENGIE EPS: Italian technology combining the power grid with sustainable mobility through V2G | FCA Archives | Stellantis (accessed 6 April 2023)

6.6.2 Grid Connected Batteries

As battery storage, including both BTM DESS and grid connected batteries, becomes more prevalent in the SWIS, they will play a prominent role in providing energy services[193] that support and promote improved system reliability and security, and can be considered as an alternative to new facilities investment or the ESM. Project Symphony tested a subset of these services, however, in order to access additional revenue streams from the additional energy services discussed in section 6.5, sufficient capacity of battery storage will be required by the VPP. The forecast uptake of DESS is expected to increase and change future minimum and maximum demand profiles over the next 10 years but note that the pace of uptake will be heavily influenced by technology improvements and a decrease in the cost of these assets.

Whilst the integration of VPP DESS tested in the Pilot demonstrated that DESS can technically support the subset of market scenarios tested, further testing is required to assess the benefits of commercial sized DESS and grid connected batteries in a VPP. A potential advantage of grid connected batteries is that it is subjected to uncontrolled loads, in contrast to DESS which may be optimised for self-consumption to minimise a customer's energy costs. This means that grid connected batteries should, hypothetically, be capable of providing a consistent response for market services in the RTM, such as bi-directional wholesale energy trade, Contingency Reserve service and regulation services, as well as off-market services such as NSS.

Studies undertaken in the NEM[194] have identified potential use cases that can be derived from grid connected batteries and BTM DESS, as shown in Figure 76, including energy arbitrage and providing frequency control ESS leading to the deferral of network augmentation expenditure and generation investment.

Grid – In Front of Meter		Garage – Behind the Meter	
System Benefits	**Commercial Benefits**	**System Benefits**	**Commercial Benefits**
Base generation and peaking plant deferral	Wholesale revenue	Base generation plant deferral	Consumer tariff reduction
Tx and Dx deferral	Power Purchasing Agreement firming	Tx deferral	FCAS revenue
Fuel savings for gas peaking plant	FCAS revenue	Fuel savings for diesel back-up plant	
Maximising utility scale intermittent utilisation		Maximising rooftop solar utilisation	
Reduced T&D power losses		Reduced T&D power losses	
Reduced unserved energy events		Reduced unserved energy events	

Figure 76: Benefits of grid connected vs BTM DESS[195]

Whilst these findings provide insights into the potential benefits of the grid connected batteries, they should also be considered in the operating context the WEM. That is, when seeking to utilise grid connected batteries or DESS to maximise value creation in the WEM, it is important to note that energy storage have

[193] Energy Transformation Taskforce, 2020c. *Whole of System Plan 2020*
[194] AECOM, 2019. *Grid vs Garage: A comparison of battery deployment models in providing low voltage network support and other services*
[195] AECOM, 2019. p. 52

limited access to energy arbitrage opportunities compared to the NEM, however following WEM reforms that came into effect in October 2023, there will be opportunities which will enable them to register to participate in the RCM. The RCM is an important source of value for grid connected batteries and DESS in the WEM and from observations of its application in the NEM, when paired with DPV, it is anticipated that will derive value from network tariffs and the capacity market. Although for grid connected batteries, the NEM generated the most value due to greater energy arbitrage opportunities arising from significantly higher energy price volatility.[196]

Whilst BTM DESS paired with DPV provides value, the distribution of this value can be inequitable. Additionally, grid connected batteries and BTM DESS can tap into different value streams, enabling these two battery types to not need to compete for access to some value sources.[197] As such, grid connected batteries remain an important potential solution for the WEM, requiring further consideration.

Western Power and Synergy's Pilot community battery program has already demonstrated a means of providing customers with access to the benefits of battery storage without the upfront capital cost. Other DNSP and retail community battery programs, such as the partnership between Endeavour Energy and Origin to deliver the Bungarribee Community Battery, have also been established to enable customers to rent capacity in the battery for $15 per month[198] and provide a return to customers between $120 and $220 per year for solar customers, and $80 to $120 per year for non-solar customers.[199] Further discussions will, however, be required in the longer term to provide further clarity on the future roles and responsibilities for grid connected batteries, and in particular the ownership and management of these assets in consideration of the operating licence conditions for Western Power and Synergy.

Notwithstanding the above, during the Pilot, a 1.3MW / 2.6MWh Western Power owned grid connected battery (constrained to 1MW) was commissioned in Harrisdale and was included in the latter stages of testing. The grid connected community battery was able to respond to an actual system event, however these assets were not in the scope of the CBA due to the low number of community batteries involved in the Pilot. Regardless, testing in the Pilot revealed capabilities above that of residential BTM DESS, suggesting grid connected batteries as a key resource to enable VPP participation across energy markets in the WEM. As such, in recognising the lack of representation of grid connected batteries in the Pilot, it is recommended that further testing should be undertaken to validate the benefits of using grid connected batteries to provide energy services, not limited to those tested within the Pilot. The benefits, practicality and commercial viability of grid connected batteries in a VPP should also be compared to BTM DESS enrolled in the VPP to determine the optimal value for aggregators and customers.

Managing the accelerated adoption of battery storage

In 2020 the Energy Transformation Taskforce, Western Power and AEMO commenced a review of compliance and monitoring of Generator Performance standards, contained within the contracts between Western Power and generators, under established technical reviews. A shortcoming identified in the review was the limited governance and self-monitoring of generator performance standards.[200]

If grid connect battery storage is registered as an RCM facility, further investigation into whether these assets should be held to the same Generator Performance Standards requiring periodic monitoring, testing, and reporting should be considered, and whether these technical standards should be applied to BTM DESS.

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[196] Tickler, 2022. *Maximising battery value: a commercial analysis of front-of-meter vs behind-the-meter storage*
[197] AECOM, 2019
[198] Endeavour Energy, 2023. [Community battery trial | Endeavour Energy]
[199] Hill, 2023. *First community battery in western Sydney now "open to rent" by residents*
[200] Energy Transformation Taskforce, 2020d. *Generator Performance Standards – Compliance and Monitoring Information Paper*

Equally, the costs of imposing this requirement should also be considered so it does not become a disincentivise for investment in energy storage.

Community Models for Deploying and Operating DER

Project Overview

The Battery Storage and Grid Integration Program (BSGIP), established by the Australian National University (ANU), conducted a socio-techno-economic analysis from 2019 to 2020 on the potential value of community batteries for customers, storage owners, and networks, across a range of ownership and operation models in the NEM.

Key Findings

- Community batteries can increase network hosting capacity, allowing more DER access to the network, with network tariffs and market signals influencing the size of the impact.
- So long as batteries are used for frequency control ESS, all ownership models are viable, with third-party ownership models providing the highest viability and potential value.
- DNSP-owned batteries require a significant proportion of battery capacity to be leased to a third-party, enabling market participation, to be commercially viable.
- Only DNSP-owned community batteries require regulatory exemptions. All other ownership models can proceed within the current rules and regulations.
- Industry experts identified significant potential benefits of community batteries, including over BTM batteries.
- Community batteries provide the most value via ESS, including provision of non-market services such as NSS.

Applicability to the WEM

Many of the challenges identified by the project relate to regulations surrounding the decentralised, competitive market structures of the NEM. For example, a community battery owned and operated by a retailer was viewed with distrust by customers as to the retailer's profit motivation, and the retailer's ability in providing NSS was restricted. Many of these issues are mitigated in the WEM, however, with Synergy as the sole retailer (and aggregator) for residential customers and Western Power as the sole network operator for the SWIS.

Additionally, the use of DOEs in Project Symphony's solution enables more efficient and effective signalling of constraints between the various market participants. By allowing Synergy to aggregate a community battery, provided bi-lateral agreements are reached beforehand, NSS can be provided quickly, allowing community batteries to address localised voltage issues. Similarly, aggregation of the community battery also allows it to provide frequency control ESS in the RTM.

Case Study 6: Community Models for Deploying and Operating DER project[201]

[201] Shaw, Sturmberg, Mediwaththe, Blackhall, & Ransan-Cooper, 2020. *Implementing community-scale batteries: Final report for the ARENA-funded Community Models for Deploying and Operating DER project*

Lake Bonney BESS

Project Overview

The Lake Bonney BESS project in South Australia, implemented by Iberdrola in July 2018 and scheduled to finish in May 2023, focused on the testing and commercial operation of a 25MW / 52MW battery, utilising Tesla's Powerpack battery technology, at Iberdrola's operational wind farm. The project sought to increase the wind farm's contracting capacity with commercial and industrial customers, increasing retail competition for these customers; use the FOM BESS to participate in the Regulation Raise and Lower and Contingency Reserve Raise and Lower markets; and reduce curtailed generation losses.

Key Findings

- The Lake Bonney BESS consistently displayed charging during the day, when DPV generation was high, and discharging during the evening peak. This shows the battery was able to successfully smooth demand curves for electricity in the SA region of the NEM.
- Over the course of the project, the Lake Bonney BESS has been increasingly used for regulation services and has been able to provide regulation frequency ESS, accurately tracking the AGC setpoints sent by AEMO every 4 seconds.
- The battery has successfully responded to contingency events within the time requirements and in line with droop settings.
- The battery was capable of taking advantage of energy arbitrage opportunities, particularly when settlement moved to five minute settlement.

Applicability to the WEM

Though there is less opportunities for energy arbitrage in the WEM, a FOM battery would be capable of being used in the capacity market for the RCM. Additionally, FOM batteries have shown themselves as capable of being used for frequency control ESS. Specifically, a FOM battery was demonstrated as able to provide Contingency Reserve Raise and Lower ESS, as well as Regulation Raise and Lower, increasing network stability and security.

The project also showed FOM batteries as capable of smoothing demand curves, successfully dispatching electricity generated by DPV systems during the day at evening peak times. As such, FOM batteries are also able to reduce curtailment and increase reliability of intermittent renewable generation, leading to increased renewable hosting capacity and reducing the need for network augmentation.

Case Study 7: Lake Bonney DESS Project[202]

[202] Iberdrola Australia, 2022. *Lake Bonney DESS: Operational Report #3 and #4*

6.6.3 Air Conditioner Load Control

Active demand response programs have traditionally focused on industrial and commercial customers, however, residential demand response programs are coming into focus as a viable alternative as smart home technologies, such as smart enabled thermostats, air conditioners and home energy management systems, become more prevalent in homes. These devices have the ability to shift consumption patterns to take advantage of lower price signals to adjust the thermal mass of homes over the course of the day, rather than heating or cooling the home during peak demand periods.

Whilst residential air conditioner (A/C) units were recruited in the VPP and initially included in the CBA, the Pilot experienced issues related to the measurement data received from the A/C units, which impacted the ability to draw conclusive outcomes. Some of these issues were attributed to compatibility and integration issues with A/C units and communications devices, whilst others were due to a dependence on customers turning on their A/C units to respond to control signals and a reliance on their internet connection to facilitate communications between the A/C unit and gateway device.

Modelling of A/C in the CBA model included an assumption that A/C load could be shifted across the day by turning the A/C down or off for a period, allowing the home to warm up and then turning the A/C back on to cool the house back down to a desired temperature set by the customer. During the modelling period, 14.56kWh would be consumed per day to cool the house in the hotter months (January and February) and 11.75kWh during shoulder periods (November, December, and March).

In discussion with Synergy, it was subsequently determined that the demand response management (DRM) control capability of A/C tested within the Pilot would not support the ability to time-shift A/C load, due to compatibility and communication issues associated with the A/C units recruited within the VPP that could not be resolved within the Pilot's stability period, and a reliance on the customer having turned on their A/C in order to be curtailed. In addition, limited A/C load data was captured during the stability period to accurately observe the benefits of DER orchestration during the hotter months where A/C would be more prevalent. For this reason, it was decided that A/C units should be removed from the CBA model, so as not to misrepresent the value of A/C in DER orchestration.

Notwithstanding the technical and practical limitation of time-shifting A/C load, separate analysis conducted by Synergy using the limited evidence available (e.g., winter consumption data) indicates that an average reduction of 7.5% in A/C load could be achieved by controlling A/C for a 15-minute period every 75 minutes, when comparing pre-event load data to post-event load data. That is, the change in A/C load following a control event did not result in a subsequent increase in load to compensate for the load that was curtailed during the 15-minute interval. It should, however, be noted that this analysis was drawn from A/C data obtained during the winter period and further testing will need to be undertaken to assess whether these findings can be interpolated to peak loads in summer. An indicative A/C consumption profile developed in work package 2.1 for a typical customer in a controlled and uncontrolled state is provided in Figure 77.

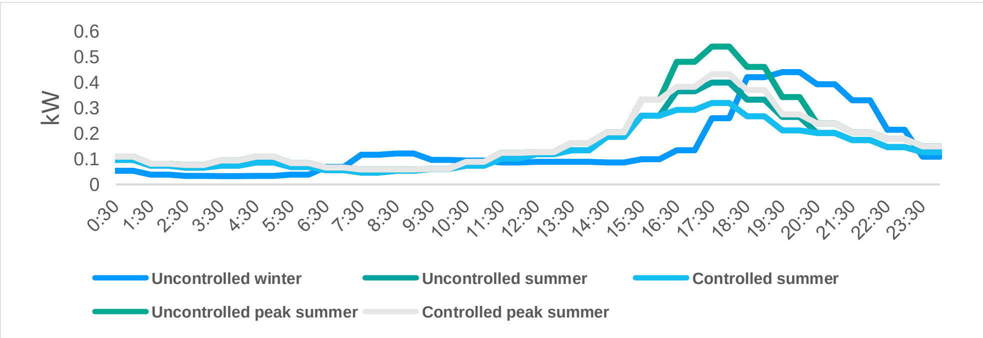

Figure 77: A/C controlled and uncontrolled consumption profile[203]

[203] Oakley Greenwood, 2022

Research conducted by RACE for 2030 (RACE) considered controlling residential A/Cs to pre-cool and pre-heat homes during periods of higher DPV generation to reduce evening peak demand. One case study mentioned in the report revealed Hong Kong using A/C demand management to reduce peak demand from 19kWh to 5kWh per day. Key learnings in the report include:

- The importance of climate on the effectiveness of pre-cooling and pre-heating, identifying cities such as Brisbane as being more suited to pre-heating, whilst cities such as Adelaide and Melbourne are more suited to pre-cooling.
- Individual household behaviour has a large impact on the efficiency of using DPV to pre-cool or pre-heat the home.
- The effectiveness of pre-cooling and pre-heating is dependent on the overall energy efficiency of the household, with greater energy efficiency leading to greater effectiveness of pre-cooling and pre-heating, though with diminishing returns as the energy efficiency rating increases.
- The financial viability of pre-cooling and pre-heating during times of high DPV generation for the household is dependent on the evening retail tariff being higher than the solar feed-in tariff by a proportion greater than the amount of evening energy saves compared to solar PV used.

However, the results show considerable savings from flexible load control of residential A/Cs, with pre-cooling in Melbourne and Adelaide resulting in a reduction of ~40% in peak A/C consumption.[204]

Another report published by CSIRO for RACE identified residential A/Cs contributing just under ~30% of zone substation summer peak demand on average for Western Power, with some zone substations attributing more than 40% of peak demand to residential A/C load. The report also suggests flexible demand management programs used to shift A/C demand could potentially reduce peak demand by up to ~12%,[205] representing a significant opportunity for the SWIS and its customers.

Residential-focused active demand management programs are still in their nascency, however, customer participation in these programs and VPPs in general will be critical to achieving the value and benefits associated with A/C load control. In addition to the key learnings identified in the RACE for 2030 report above, other considerations to maximise the value of A/C load control include:

- Providing customers with greater flexibility on how they participate in demand response programs, such as what assets can be controlled and for how long or providing the option to opt-out.
- Increase focus on customer incentives and rewards, such as bill credits or financial rewards for customers who participate in demand response programs, to lift customer engagement and participation.
- Leveraging advanced metering infrastructure (AMI) to better understand customer behaviour and target demand response programs more effectively. The latest generation of smart meters not only remotely measure electricity consumption, but also have the capability to control appliances. The UK government, for example, is currently running a programme to trial the use of smart metering systems as a key component of a residential demand response program across ‘smart’ energy appliances.[206]
- Develop more sophisticated demand response management systems and interoperability protocols, that enable aggregator to seamlessly adjust customer loads in response to changing grid conditions, without the need for manual intervention.

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[204] RACE for 2030, 2021b. *Residential solar pre-cooling and pre-heating: final report*
[205] Goldsworthy, Brinsmead, & White, 2021. *Discussion Paper for the RACE CRC "B4 Flexible Demand Opportunity Assessment"*
[206] Department for Energy Security and Net Zero, 2022. [Interoperable Demand Side Response programme - GOV.UK (www.gov.uk)]

Due to the measurement issues encountered during the testing of A/C systems and decision to exclude A/C systems from the CBA model, additional testing and data is required to assess A/C load control capability. It is recommended that further trials be undertaken to understand and quantify the benefits of A/C orchestration and load shifting capabilities (e.g., pre-cooling of homes); and to increase customer awareness of the benefits of these programs and development of appropriate incentives to promote and sustain participation.

6.6.4 Hot Water Load Control

Water heating makes a large contribution to peak demand in the NEM, comprising 25% of household energy use in Australia (the second largest segment of household energy consumption behind space heating and cooling).[207] However, with the increasing focus on demand response programs, storage-based water heaters also present one of the largest opportunities to be orchestrated under a VPP. Electric storage-based water heating, as large appliances consuming high amounts of energy, hold high potential to be used as flexible and controlled loads since they deliver the same value to the customer independent to the time of day the load consumes energy. As such, by aggregating these loads and controlling them under a VPP, they provide capabilities to respond to signals to increase demand during the day, when solar generation is high and demand is generally low, decreasing their contribution to peak demand during the evening, and minimising any impact to the customer whilst simultaneously improving power system conditions.[208]

Electric hot water heating systems (HWS) are less prevalent in the WEM compared to the NEM, with gas systems being the predominant form of heating used in WA in established dwellings. Furthermore, the number of available electric hot water assets enrolled in the VPP was too low to be statistically significant, so it was decided to exclude hot water systems from the CBA modelling. Historically, electrical technology used to heat water has been inefficient with high costs, leading to households relying on gas systems instead. However, there has been substantial advancements in electrical technologies, leading to highly efficient electric hot water systems with reduced costs. The Renew Energy Projects Team determined that it is more economic for new homes to avoid gas connections, utilising electricity for all their appliances. For existing homes, the analysis revealed that it is more economic to switch to electric appliances, with few scenarios revealing only marginal benefit. Combined with the increasing number of DPV systems installed, WA households are likely to gain increased benefits from installing electric hot water systems. As such, as gas hot water systems reach their end-of-life, the decision to switch to an electric HWS will be influenced by the upfront capital cost of HWS, which is currently higher than a gas system.[209] Incentivising customers to switch from gas to electric HWS, therefore, needs to provide a compelling value proposition for customers that demonstrates that they will be better off overall over the lifecycle of electric HWS, whilst also providing a greater opportunity to utilise hot water systems as orchestrated DER under a VPP.

To understand the potential value available from electric HWS in the WEM, data from the NEM can be used to infer an estimate of the energy use per customer attributed to HWS. With 204,000GWh of electricity supplied in the NEM each year[210] and 25% of household energy use attributed to HWS (mentioned above), electric HWS contribute roughly 51,000GWh to energy use in the NEM each year, or 4.8MWh per customer each year. Assuming this translates to the WEM, this would translate to an additional $1,443 per customer each year in retail tariff revenue for Synergy and an additional $423 per customer each year in network charges. In terms of load control, however, research suggests ~24GWh of shiftable load from HWS is

[207] Marchment Hill Consulting, 2021. *SA Smart Network Project: Performance Report 1*
[208] AEMO, 2021a
[209] Reddaway, 2021. *Affordable energy choices for WA households*
[210] AEMO, 2021f. *The National Electricity Market Fact Sheet*.

available per day in the NEM,[211] suggesting 2kWh per customer per day is available to be shifted to high DPV generation periods. This reduces the increase in customer bills on an annual basis to $1,224 per customer, with the increase in network charges reduced to $359 per customer. When considering this impact in the context of the wider services electric HWS are being tested in, it stands that there is considerable upside to exploring flexible load control of electric HWS in the WEM. However, this is highly indicative and more testing needs to be done, capturing WEM-specific data to provide a more accurate basis for potential value.

Although hot water load control was included as part of the Pilot, a lack of statistically significant representation and controllable load measurement issues resulted in their exclusion from the CBA modelling and analysis. Given the low number of these assets included in the Pilot and exclusion form the CBA, it is recommended that future pilots or trials should include electric HWS, ensuring statistically significant representation, to validate the viability and value of orchestrating these assets in a VPP. Future testing should also consider the value of different types of HWS and control methodology used. The engagement approach used in the Piot sought to subsidise upgrading customer HWS to a heat pump HWS, controlling the heat pump via the VPP, rather than enlisting existing HWS. This approach restricted some of the control benefits available from HWS control as the system changes from a 3.6kW resistive load to a 0.6kW heat pump load. It is further recommended that the recruitment of HWS should be targeted in specific locations of the network, where localised network constraints are emerging or already exist, so that sufficient capacity of controllable loads can be orchestrated at specific locations to defer network augmentation.

[211] Heslop, Beletich, Guerrero Orbe, Pang, Rahimpour, Zhang, Khalilpour, Dwyer, Berry, Bruce, MacGill, & Rundle-Thiele, 2023. *Facilitating smarter homes*. Prepared for RACE for 2030 CRC.

Off-Peak Plus Programme

Project Overview

The Off-Peak Plus programme launched in 2021 was a collaboration between Endeavour Energy and Intellihub, in partnership with ten energy retailers, to install 2,500 smart meters at homes in Albion Park, a suburb approximately 100km south of Sydney, NSW. With the Albion Park load control unit coming to the end of its life, the programme aimed to remove the need to replace the unit by using the smart meters to provide load control services.

Specifically, the programme aimed to control electric hot water systems to use electricity during off-peak times and be switched off during peak demand times, reducing peak demand and smoothing demand curves.

Key Findings

The programme has provided the following benefits:

Endeavour Energy's customers

- Increased network reliability.
- Increased renewable energy hosting capacity, such as DPV.

Energy networks

- Avoided investment in network augmentation.
- Improved visibility of LV distribution networks.
- Increased network stability and security
- Demand curves are smoothed, moving a proportion of peak demand to off-peak times.

Retailers

- Increased opportunities for innovative products using DER.

Applicability to the WEM

As electric hot water systems increase in the WEM, they have the potential to significantly increase peak demand. By using smart meters to control these types of loads, peak demand can be effectively managed.

By controlling hot water systems, these loads can be used to soak up excess energy from DPV systems, decreasing the need to curtail these renewable energy sources and increasing the intermittent renewable generation hosting capacity of networks in the WEM.

Finally, by managing the import of electricity of these loads, there is potential for them to be aggregated and used for frequency control services, as well as voltage control related NSS to address localised issues.

Case Study 8: Off-Peak Plus Programme[212,213]

[212] Jones, 2021. Smart meters for hot water system control in New South Wales community (smart-energy.com) (accessed 22 April 2023)
[213] Endeavour Energy, 2021. Fact-Sheet-Endeavour-Energy-Off-Peak-Plus.pdf (intellihub.com.au) (accessed 22 April 2023)

6.7 Greenhouse Gas Emissions Reduction

In line with the WA Government's *Climate Action Policy*, one of the objectives in WA's Energy Transformation Strategy seeks to reduce emissions across the energy sector by increasing the amount of renewable generation in WA's energy networks enabling the connection of DER to the electricity system and maximising DER hosting capacity, [214]

Distributed generation such as DPV can contribute to a reduction in overall greenhouse gas (GHG) emissions by supplying customers with electricity generated using renewable sources, reducing the volume of electricity generated using traditional sources, such as thermal generation. Current GHG emissions data is reported by the CER, including the electricity sector's emissions and generation data for the financial year at a designated generation facility level. Figure 78 shows the volume of carbon emissions for the volume of electricity produced between financial years ending 2019 and 2022.

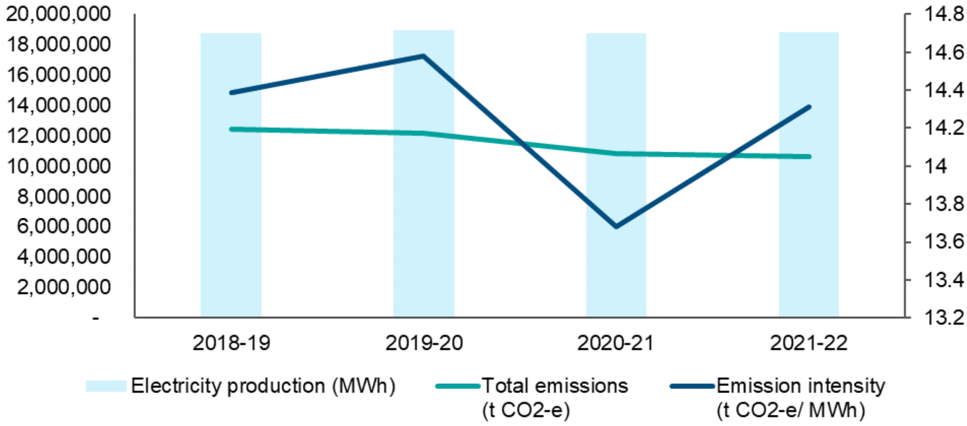

Figure 78: Annual emissions of designated generation facilities in the SWIS[215]

Importantly, this only captures data relating to designated generation facilities, which are facilities used primarily for electricity generation, so does not reflect growing demand of electricity. However, it does show generation required from these designated facilities has remained stable over the last four years, suggesting an increase in generation from other types of facilities. Additionally, despite this stable production, total emissions have decreased by 14.47%, reflecting the increasing renewable generation mix in the SWIS.

Though the rise of DER in the SWIS provides significant opportunities in supporting WA reach its climate action goals, the challenges connected to increasing DER remain. Project Symphony demonstrated a potential solution to these, using a VPP to orchestrate DER and manage system security and stability, ensuring the network remains within safe operating bands. However, to successfully transition to renewable energy, the solution must also address renewables' intermittent nature. By orchestrating both battery storage and smart inverters, a VPP is able to address this, improving network reliability of renewable energy.[216] Additionally, with the forecasted rise in EVs in WA and continued advancement in technology such as V2G, the capabilities of orchestrated DER in smoothing demand curves and addressing peak demand periods, including for use in the RCM, will continue to grow.

The impact of DER orchestration on GHG emissions was not considered in the scope of the CBA and as such more extensive modelling will be required to determine the extent to which a VPP can contribute to GHG emissions in the SWIS in both the short and long term. This analysis will need to consider the

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[214] Department of Treasury, 2019. *Energy Transformation Strategy: A Brighter Energy Future*

[215] Sourced from: Clean Energy Regulator, 2023. Electricity sector emissions and generation data (cleanenergyregulator.gov.au) (accessed 27 April 2023)

[216] Cox, Gagnon, Stout, Zinaman, Watson, & Hotchkiss, 2016. *Distributed Generation to Support Development-Focused Climate Action*

examination of use cases where aggregated DER can defer or contribute to the avoidance of expenditure on baseload and peaking generation.

Onslow DER Project

Project Overview

The Onslow DER Project was implemented by Horizon Power, in partnership with PXiSE Energy Solutions and SwitchDin, from 2019 to 2021 in Onslow, a small regional town in WA's north-west. The project combined a mix of distributed renewables, including residential, commercial, industrial and utility-scale solar, modular gas-powered generation, and battery storage to create a microgrid, providing up to 50% of Onslow's energy demand via renewable sources.

To do this, the project utilised a Distributed Energy Resources Management System (DERMS) with the Secure Gateway Device (SGD) to ensure seamless communication and control capabilities to effectively manage DER generation in the grid.

Key Findings

The project successfully enabled:

- 100% of generation was successfully provided by renewable sources for 80 minutes, proving 100% renewable generation is possible.
- Increase the hosting capacity of the network to accommodate additional rooftop solar connections
- Deliver up to 50% of Onslow's energy requirement via renewable energy.
- Successful management of DER connected to the microgrid.
- Horizon Power transitioning the Onslow power station directly under its management and creating the renewable-focused microgrid saw an overall reduction in direct carbon emissions.

Applicability to the WEM

DER orchestration is able to increase renewable generation hosting capacity in networks. By using Project Symphony's solution to enable more DPV to be connected to the SWIS, the need to invest in traditional energy sources, such as coal and gas, is minimised. Additionally, with the forecasted increase in battery storage in the WEM, there is greater ability to address the intermittent nature of solar generation and increase network reliability.

The project also shows the possibility of moving to 100% renewable generation in the SWIS. Though more work needs to be done to ensure system stability and security and to further solidify network reliability, 100% renewable generation presents an opportunity to drastically decrease carbon emissions.

Case Study 9: Onslow DER project

7. Conclusion

Project Symphony provided an active demonstration of the functional capability of DER orchestration via a VPP and, through the CBA, sought to quantify the potential benefits that could be achieved when delivered at scale. The results of the CBA reveal a clear net benefit to DER orchestration, particularly when co-optimising DER assets across all services tested in the Pilot. This is further evident when considering the limitations of the Pilot and the CBA, with only a narrow set of DER assets considered across a sub-set of value streams, and conservative assumptions used in the CBA (e.g., DPV and DESS system size, DOEs, etc.), resulting in a conservative assessment of the potential value of DER orchestration in the WEM. As such, the net benefits identified should be considered a conservative evaluation of DER orchestration in WA, with significant upside potential as additional DER assets are enrolled in VPPs and services are broadened to other market areas.

There are numerous upside opportunities for WA to capture greater DER orchestration value in practice. Timely and assertive action can deliver material benefits to the industry and to consumers and help accelerate the transition to net zero. As outlined in the recommendations, this includes actions to:

- Eliminate barriers to customers investing in larger sized DPV, such as the introduction of dynamic connection agreements.
- Reducing capital and operating costs via focused investment in DER and targeted recruitment of high-value DER in specific locations, increasing the opportunity for deferral of network investment and generation investment.
- Expanding both the types of DER enrolled in the VPP and the number of market services provided by the VPP. In this regard, more work is required to ensure aggregated DER has the required capabilities to provide these other services.

To this end, additional work will be required to develop the commerciality of a VPP and to ensure the financial benefits are equitably distributed across all participants when delivered at scale across the SWIS, and that consumers with and without DER are no worse off.

The recommendations in the CBA focus on scaling Project Symphony's solution to the SWIS. However, questions remain that fall outside the scope of this Pilot and the CBA. To continue to advance DER orchestration in the WEM, two additional areas need to be considered, with subsequent recommendations:

7. Analysing the impact of a VPP from a whole-of-system perspective.

Though the results support DER orchestration via aggregation through a VPP, the limitations of Project Symphony and, subsequently, the CBA, restricts the depth of learnings available. As mentioned, the *Electricity Industry (Distributed Energy Resources) Amendment Bill* seeks to introduce a new overarching objective centred on protecting the long-term interests of end-use customers by ensuring reliable supply of electricity and reducing associated greenhouse gas emissions.[217] Though the impact on carbon emissions from implementing Project Symphony's solution across the SWIS was qualitatively assessed, in-depth quantitative analysis must be conducted to provide an accurate picture of the degree to which Project Symphony aligns with the new SEO. Similarly, the impact a scaled Pilot has on system reliability cannot be accurately determined without considering how a VPP interacts with the wider market. To ensure Project Symphony's solution addresses the proposed SEO in an affordable manner, whole-of-system modelling is required, including assessment of a VPP's impact on cost recovery mechanisms, demand-side programs, generators, retailers (not just Synergy), and all customers (contestable and non-contestable).

The following provides a summary of these recommendations:

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[217] Energy Policy WA, 2023d.

Ref No.	Recommendation
7.1	Conduct in-depth, whole-of-system modelling, expanding on the CBA by incorporating all market participants (retailers, generators and ESS providers) in the SWIS, cost recovery mechanisms for AEMO and Western Power, and both contestable and non-contestable customers to quantify the full potential value available from Project Symphony's solution.
7.2	Compare findings from the in-depth, whole-of-system modelling in the short-term and medium-term with the short-term and medium-term Projected Assessment of System Adequacy reports published by AEMO to determine a VPP's impact on system reliability.
7.3	Utilise published measures on CO_2 emissions to quantitatively assess the impact of a VPP on emissions in the SWIS.

8. Establishing a competitive TPA market.

Testing of TPAs in the Pilot was limited, with TPA operations confined to ~2 hours per day. Though the CBA included TPAs to assess their impact on the VPP, it did so by attributing a flat percentage of customer DER to the TPA based on the ratio of assets enrolled via Synergy compared to TPAs in the Pilot. Additionally, the commercial arrangements in the Pilot, and subsequently, the CBA, are not reflective of a competitive TPA market, with the CBA results showing a negative NPV for TPAs across all test scenarios in all modelling scenarios. To offset this, sensitivity analysis considered alternative commercial models between TPAs and Synergy, and TPAs and their customers, however, with their operations substantially limited and a simple ratio used in the CBA modelling, more work is required. Firstly, in line with other recommendations, additional testing and modelling is required to assess the value provided to TPAs when allowed to operate as they would in a live market.

To support modelling of TPAs in a live market, policy must provide TPAs with a framework that takes a hands-off approach, allowing innovation and flexibility in business models. To ensure TPAs and their customers are adequately compensated, it is recommended minimal regulatory interference is introduced, allowing incentives TPAs award to customers to be set by natural market forces (this would be tempered by the payments made by Synergy, with customers assumed to enrol via Synergy if TPA payments are below that offered by Synergy); and allowing TPAs to set their fees charged to Synergy, incentivising continued investment in technology and focused recruitment of DESS and other high-value DER by TPAs to ensure they are able to offer competitive services to Synergy and attain sufficient market share. This allows TPAs flexibility to adopt more innovative business models, such as an Energy as a Service model, where they lease DER assets to Synergy rather than charge based on operational use. It also allows for a competitive market, providing market power to the customer. Initially, customers will be able to benchmark TPA offerings against that of Synergy, providing them with the necessary knowledge to make informed decisions. However, it also allows Synergy flexibility to move away from direct enrolment of customer DER, taking advantage of the business models employed by TPAs to manage costs efficiently and drive down their costs as the parent aggregator.

Finally, monitoring processes must also address the opportunity for TPAs to be registered market participants serving contestable customers. Under the WEM Rules, Synergy is the only retailer/aggregator allowed to serve non-contestable customers (e.g., residential customers) as a means to protect these customers from higher energy prices. Contestable customers, however, can be served by any retailer or aggregator registered as a market participant. Theoretically, TPAs may enrol residential customer DER to provide a service to Synergy as the parent aggregator, whilst also being a registered market participant for contestable customers. This provides opportunity for TPAs to potentially use customer DER for the purposes of serving their contestable customers, rather than for enrolment in a VPP managed by Synergy. As such, additional monitoring processes are required to ensure TPAs are not able to blur the lines of contestable vs. non-contestable customers.

A summary of the recommendations relating to TPAs is provided below:

Ref No.	Recommendation
8.1	Conduct further testing of TPAs without restricting their operations, allowing them to operate as they would in a live market, with operations determined by price signals and other market powers.
8.2	Encourage the participation of TPAs in the non-contestable market, under the direction of the parent aggregator, whilst enable TPAs with the flexibility to participate in the contestable market

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Appendix 1: Acronyms and Glossary of Terms

Acronym / Term	Definition
AEMO	Australian Energy Market Operator
Aggregator	A party who facilitates the grouping of DER to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s).
BTM	Behind-the meter: Any technology located on the customer's side of the customer-network meter.
DER	Distributed energy resources: Small-scale energy resources that are connected to the distribution network that can produce electricity or actively manage demand. Examples of DER include residential solar PV and batteries and electric vehicles. Proposed changes to the EI Act and introduction of the Electricity System and Market Rules will define the inclusion of DER, embedded generation and microgrids in the distribution system. These resources operate for the purpose of supplying all or a portion of the customer's electric load and may also be capable of supplying power into the system or alternatively providing a load management service for customers.
DERMS	Distributed Energy Resources Management System: A software platform for the management of distributed energy resources.
DESS	Distributed Battery energy storage systems: small distributed behind-the-meter battery storage systems installed for residential, commercial, and large commercial customers, that do not hold Capacity Credits in the WEM
DOE	Dynamic operating envelopes: Limits on customer imports and exports to the electricity grid that can vary based on time and location. Dynamic rather than fixed export limits could enable higher levels of energy exports from customers' DER by allowing higher export limits when there is more hosting capacity in the local network.
DMO	Distribution Market Operator: The DMO is responsible for managing the electricity system and market and an extension of AEMO's current responsibilities
DNSP	Distributed Network System Provider: Defined in the National Electricity Rules as *'A person who engages in the activity of owning, controlling or operating a distribution system.'*
DSO	Distribution System Operator: A DSO enables access to the network, securely operating and developing an active distribution system comprising networks, demand, and other flexible distributed energy resources.
EPWA	Energy Policy WA

ERA	Economic Regulation Authority: The regulating body responsible for administering State-based arrangements for electricity networks in the Southwest Interconnected System.
ESS	Essential System Services: Previously known as Ancillary Services, these are the non-energy services that ensure the parameters of the network stay within suitable limits to keep the grid in a stable and reliable state.
EV	Electric Vehicle: A type of vehicle that has an electric motor and batteries, instead of an internal combustion engine, relying on gas or liquid fuels.
FCESS	Frequency Co-optimised Essential System Services - The essential system services that relate to the management and control of frequency within the network.
FTM	Front-of-the-meter: (also referred to a grid connected and front-of-meter) Any infrastructure located on the distribution network side of the customer meter (i.e., not behind the meter).
HVAC	Systems and equipment used in heating, ventilation and air-conditioning
NCESS	Non-Co-optimised Essential System Services: The ESS that are not frequency-related and usually occur in a specific location, resulting in an inability to co-optimise.
NEM	The National Electricity Market operating as an interconnected network across Queensland, New South Wales, ACT, Victoria, Tasmania and South Australia.
NSS	Network Support Services: Services that assist in maintaining stable and safe network operations and managing network congestion, including active power response (load or generation), and voltage control
SWIS	Southwest Interconnected System
V2G	Vehicle-to-grid
VPP	Virtual power plant - VPPs are the notional entities comprised of aggregated and controlled DER components, which can provide generation and system support functions, and participate in energy markets (like traditional generators).
WEM	The Wholesale Electricity Market, operating in the SWIS.