30 November 2023

Ausgrid’s 2024-29 Revised Proposal

Attachment 5.7.1: CER Dynamic Services business case

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

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1. CER – Dynamic-Service

1.1 AER's Draft Decision

Our dynamic-service capabilities revised proposal requires an investment of $8.1m to enable dynamic pricing, dynamic operating envelopes (**DOEs**) and the associated systems required to support them. This includes $1.4m SaaS costs which were previously treated as opex in our initial proposal. The remaining $3.9m in supporting opex is included in Attachment 6.1. The total investment is unchanged from our initial proposal.

This proposed investment will deliver significant benefits to consumers by making more efficient use of our existing export capacity and creating financial opportunities for network users by rewarding the coordination of flexible generation and demand.

The AER's Draft Decision did not accept our initial regulatory proposal, concluding that no allowance should be provided to enhance our dynamic-service capabilities. As explained in the table below, the AER's principal concern related to the method we adopted for estimating the market benefits from our proposed investment.

What we heard	How we've responded
Dynamic service capability is expected to deliver 'market efficiencies'. However, these benefits have been overstated by Houston Kemp, as its analysis is based on differences in wholesale prices rather than customer export curtailment values (CECVs).[1]	We have updated our modelling to apply the **CECVs** to re-estimate the market benefits. While the 'central case' with updated analysis results in lower benefits compared to our Initial Proposal, it shows that the proposed investment delivers a net benefit compared to the 'do nothing/BAU' option. Our updated modelling results are presented in **Section 1.3** below.
If Ausgrid's analysis is updated to include our recently published CECVs, the benefits will likely outweigh the proposed costs. However, we are unable to replicate Ausgrid's analysis with a high level of certainty, and so we encourage Ausgrid to update its analysis in its revised proposal.[2]	The updated analysis supports the proposed investment. As such, this Revised Proposal in relation to dynamic service capability is consistent with the AER's commentary in its Draft Decision.

While the AER disallowed the proposed investment on the basis that the benefits had been overstated, the AER acknowledged that an economic case for the proposed investment could be established. The updated modelling confirms that benefits outweigh the proposed costs.

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1 AER, Draft Decision, Ausgrid Electricity Distribution Determination 2024 to 2029, Attachment 5, page 43.

2 Ibid, page 46.

1.2 Context for this project

Before addressing the modelling issues raised by the AER's Draft Decision, it is helpful to provide background information to explain the broader context for the proposed investment in dynamic-service capabilities.

Dynamic network prices allow customers, aggregators and virtual powerplants (**VPPs**) to receive more cost-reflective price signals that vary by forecast network use. This pricing information provides customers with more opportunities to trade in energy markets and enables price-responsive network support.

The groundwork for introducing dynamic pricing and DOEs is already underway and has strong consumer support. As detailed in our Tariff Structure Statement (**TSS**) Explanatory Statement[3], we are currently undertaking a trial of this approach via Project Edith. It is a proof of concept and proof of capability that we can send dynamic network prices, and that customers (through aggregators) can respond effectivley to those price signals.

Project Edith is currently a small-scale trial with a single aggregator partner representing less than 300 participating customers. Having successfully engaged stakeholders in Project Edith, we are now preparing to expand the trial to:

- Include additional aggregators;
- Increase customer participation; and
- To demonstrate and validate the dynamic pricing concept.

The trial and its expansion have been enabled by Ausgrid's 2019-2024 Network Innovation Program funding and supported by our Network Innovation Advisory Committee.

Our Pricing Directions Paper consultation[4] asked stakeholders for their views on how we can continue to build and test dynamic network pricing through the 2024-29 period. In its submission to that consultation paper, the Public Interest Advocacy Centre (**PIAC**) supported Ausgrid building its capability to effectively implement dynamic network pricing in the 2024-2029 period, including through tariff trials. The City of Newcastle also supported the continuation and extension of Project Edith.

Since our Initial Proposal, there is evidence of a growing understanding of the opportunities provided by dynamic pricing and DOEs, and an expectation that networks will provide this capability. For example:

- Project Edith received the 2023 Industry Innovation award from Energy Networks Australia.[5]
- Project Edith expansion phase attracted formal proposals from 8 VPP aggregators/retailers, demonstrating the market need for a dynamic network service.

3 Attachment 8.2 - Our TSS Explanatory Statement for 2024-29.

4 Ausgrid, Our Pricing Directions Paper for 2024-29, September 2022.

5 https://www.ausgrid.com.au/About-Us/News/ENA-Award-Win/.

- The AEMC's Directions Paper on Unlocking CER Benefits Through Flexible Trading highlighted Project Edith as one of the important initiatives that is creating new opportunities for the integration of CER into markets and network capacity management.[6]
- AEMO's 2023 Electricity Statement of Opportunities[7] highlighted commitments to programs of CER orchestration (e.g., VPPs) as one of the ways in which reliability risks could be addressed. From a practical perspective, however, orchestrated CER depends on investment in dynamic pricing and DOE as enablers.

This highlights that there is already strong interest and momentum behind the concept of dynamic service capabilities. The challenge is to ensure that our proposed investment is appropriate for the level of expected benefits. We address this question, which the AER raised in its Draft Decision, in **Section 1.3**.

1.3 Updated modelling results

The AER's feedback focused on our estimate of market efficiency benefits, which are provided by enabling VPPs and aggregators to arbitrage the price difference between fluctuating wholesale market prices. By enabling VPPs and aggregators to respond to these arbitrage opportunities, the costs of meeting demand at peak times are lower than would otherwise be the case. The market efficiency benefits are calculated by comparing the behaviour of VPPs, including vehicle-to-grid (**V2G**)-enabled electric vehicles (**EVs**), accessing dynamic network pricing and DOEs, against their behaviour in the base case of static prices and static export limits.

In its Draft Decision, the AER observed that while these price differences drive the arbitrage opportunities, the economic value depends on differences in CECVs rather than wholesale prices. We have responded to the AER's feedback by engaging Houston Kemp to re-calculate market benefits using differences in CECVs (See **Appendix A**).

Our Revised Proposal analysis employs the following updated data and input assumptions:

- Oakley Greenwood's CECVs have been used to quantify the benefits of the shift in generation and load resulting from the optimisation, in accordance with the AER's Draft Decision.
- We have updated the prices and structure of tariff to reflect the EA025 structure and the indicative prices proposed in our TSS.
- We have updated the projections of VPP and EV take-up, based on AEMO's 2023 Inputs Assumptions and Scenarios report (**IASR**)[8]. We have retained the assumption that 50% of customers in VPPs take up dynamic services.

Our updated modelling results in the table below show that the benefit from our initial proposed expenditure reduces from \$96.0m to \$56.4m in our revised regulatory proposal. Importantly,

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6 AEMC, National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule 2023, Directions Paper August 2023, page 14.

7 https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/2023-electricity-statement-of-opportunities.pdf/.

8 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/.

however, the net benefit remains positive at $16.8m in present value terms, with respect to totex costs over the 2024-2044 analysis period.

Table 1: Updated cost-benefit analysis for dynamic-service capabilities (real $m, FY24), expressed in PV terms

Option	Benefit	Costs	Net benefit
1. Initial regulatory proposal	96.0	39.6	56.4
2. Revised regulatory proposal	56.4	39.6	16.8

In summary, **Table 1** indicates that our proposed investment in dynamic service capabilities is justified on the basis of market efficiency benefits. Our Initial Proposal also outlined further benefits, including $31.8m in deferred investment and avoided opex. Our sensitivity analysis indicates that the net benefits from our proposed investment may be materially higher than shown in **Table 1**.

1.4 Sensitivity analysis

We have applied conservative assumptions to the modelling of market efficiency benefits presented in the previous section, referred to below as the 'central case'. We have undertaken a sensitivity analysis to model potential benefits, by varying the following assumptions:

- **Static export limit**: Our central case modelled a 5kW static export limit, which is high compared to other networks. We have therefore included two sensitivities based on static export limits adopted by other networks:
  - a 3kW static limit as an alternative to a dynamic limit.
  - a 1.5kW static limit as an alternative to a dynamic limit.
- **Value of emissions**: The value of emissions was not included in the central case. We have therefore included a sensitivity that values emissions at $30 per tonne of CO_2e consistent with **Ausgrid - Att. 5.7 - Ausgrid CER augmentation business case - 30 Nov 2023 - public**. This is a conservative placeholder value inputed in absence of alternative formal guidance as market bodies and jurisdictions work to implement the inclusion of emission in the National Electricity Objectives.
- **Relax perfect foresight**: The central case assumed perfect foresight in a VPP optimiser, which has the effect of over-estimating the market participation in the base case of static services, thus reducing the benefit from investing in dynamic-service capabilities. In this sensitivity, we relax the assumption of perfect foresight to provide a more realistic assessment of the value provided by dynamic pricing and DOEs.

The results of this sensitivity analysis are provided in **Table 2** below, alongside the central case shown in row 1. Refer to **Appendix A** for a more detailed analysis and basis of preparation.

Table 2: Sensitivity analysis for dynamic-service capabilities (real $m, FY24), expressed in PV terms

Sensitivity	Benefit	Costs	Net benefit
1. Revised regulatory proposal (central assumptions)	56.4	39.6	16.8
2. 3kW static export limits	78.9	39.6	39.3
3. 1.5kW static export limits	109.3	39.6	69.7
4. Include value of emissions	78.0	39.6	38.4
5. Relax perfect foresight	199.1	39.6	159.5

Table 2 shows that each sensitivity analysis would increase the net benefits compared to be central case. Therefore, the analysis indicates that the central assumptions employed in the model are conservative, i.e. they tend to understate the likely net benefits from the proposed investment.

In summary the sensitivity analysis reinforces the economic case for proceeding with the proposed investment in dynamic-service capabilities.

1.5 Other factors, not modelled

In addition to the sensitivity analysis, there are several other factors that have not been modelled that are likely to provide additional benefits compared to the central case. These factors are described briefly below.

- **Promoting wider take-up**: The revised model only estimates the benefit assuming the projected uptake of battery storage VPPs, and V2G-enabled EVs under AEMO's 2023 IASR, step-change scenario. The modelling does not account for the likely increased growth in these segments resulting from greater value that is unlocked by our dynamic-services investments. Nor does the model consider the positive externalities from Ausgrid's successful introduction of dynamic network pricing on other networks, which tend to promote increased market participation across the NEM.

  The modelling also does not consider the additional participation of flexible loads like hot-water or alternative storage options like community batteries, which create the opportunity to further grow the VPP segment beyond the ISP assumptions.

- **Avoiding static export limits**: The market benefits assessment has been limited to customers projected to participate in VPPs and V2G charging. However, these investments also prepare the foundation for flexible exports to be an option for all Ausgrid solar customers, as is the case in South Australia and soon to be in other states. If the dynamic services investments are approved, then we will be ready for a widespread rollout of flexible exports by 2030 or earlier, should the need be established. If the investments are not approved, then we risk requiring inefficient static export limits or costly augmentation in the 2029-34 period.

- **Emergency minimum-demand backstop**: This backstop would be used as a last resort to avoid local or state-wide blackouts during rare minimum system load emergencies. The timing of the need for an emergency minimum demand backstop in NSW is not yet clear, although one has already been introduced in Western Australia, South Australia and Queensland, with Victoria following in July 2024. If an emergency minimum demand backstop is required in NSW during the 2024-29 period, our proposed dynamic services investments will deliver additional value by providing the foundation for using Common Smart Inverter Profile Australia (**CSIP-Aus**)[9] to enact the backstop, making it consistent with Victorian and South Australian implementations.

We note that more sophisticated modelling could be developed to value these additional benefits. As the current modelling already justifies the proposed investment, it is not necessary to extend the modelling to account for these benefits. Furthermore, in the context of the AER's Draft Decision, extending the analysis in this way would likely to cause confusion and raise concerns that additional sources of benefits were being introduced in the updated modelling. Instead, the approach adopted in this business case is to update the modelling to address only the concerns raised by the AER in its Draft Decision.

1.6 Concluding comments

Our updated modelling shows that the proposed investment of $8.1m, along with $3.9m of supporting opex[10], in dynamic services capability is justified. This conclusion is consistent with the AER's commentary in its Draft Decision, which anticipated that there would be an economic case for the proposed expenditure.

Our updated modelling described above corrects the overestimation of the market benefits in our initial regulatory proposal. Furthermore, this updated analysis has helped to identify other benefits that are likely to arise if the central-case assumptions are varied, as explained in our sensitivity analysis. We have also identified several other factors that are likely to lead to additional benefits which have not been reflected in our model. Evidently, if an allowance were made for these additional benefits, the case for proceeding with the proposed investment in dynamic-service capabilities would be even stronger than indicated in the cost-benefit analysis.

More broadly, there is a strong case for investing in dynamic-service capabilities as Australia transitions to a lower carbon economy. This project will build on the progress that has already been made through Project Edith to the benefit of our customers and in accordance with expectations of AEMO in its role as system operator.

9 The 'Common Smart Inverter Profile – Australia' was developed by the DER Integration API Technical Working Group. This working group formed in 2019 as a collaboration of Australian energy sector businesses from across the supply chain, including numerous distribution networks, retailers, equipment manufacturers and aggregators.

10 See Attachment 6.1 – Proposed operating expenditure.

2. Appendix A: Economic benefits of Distribution System Operator (DSO) Investments

Economic benefits of Distribution System Operator investments

A report for Ausgrid

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Executive summary

Australia's electricity markets are going through a period of fundamental change as they transition from a centralised system of large fossil fuel generation to a renewable energy future. Consumer energy resources (CERs) on the distribution network such as rooftop solar photovoltaic (PV), community batteries and electric vehicles (EVs), are expected to play an increasingly important role. A key challenge for distribution network service providers (DNSPs) is how best to manage the emergence of CERs in a cost efficient manner. Put another way, there is a risk that network limitations will limit CERs from operating in a manner that maximises their beneficial contribution to the electricity market.

To address this problem and capture this opportunity, DNSPs are investing in systems and processes to improve the localised management of the network. Through the development of dynamic network management practices such as dynamic network prices and dynamic operating envelopes (DOEs), DNSPs are becoming Distribution System Operators (DSOs), which allows them to manage the operation of the network in a more dynamic way.

Within this context, Ausgrid has engaged HoustonKemp to understand the broader, non-network economic benefits of its planned investments to build capabilities as a DSO. To understand these benefits, we have focused our analysis on analysing how DOEs and dynamic network prices – two of the key capabilities resulting from DSO investments – affect the operation of virtual power plants (VPPs) and EVs capable of exporting to the grid. We then value how the change in VPP and EV participation in the wholesale electricity market delivers corresponding market benefits.

For the remainder of this report any reference to an EV refers to an EV capable of exporting to the grid, when required. It is these smart EV charging systems that are expected to benefit the most from DSO capabilities, both in aggregate and on a per unit basis.

How do dynamic operating envelopes and dynamic prices lead to wholesale electricity market benefits?

DOEs and dynamic prices change how VPPs and EVs integrate with the wholesale market.

As the number of CERs connected to the grid increases, the network will become increasingly constrained. To maintain grid stability, a DSO will either need to increase network hosting capacity or put in place a static export limit on CERs connected to the grid. A static export limit places a fixed limit on the exports from a VPP or EV and is applied to all periods of time across a day, and to all days across a year.

It follows that a static export limit will prevent some VPP and EV capacity (as well as rooftop solar PV not part of a VPP) from exporting even during time periods where there are no network constraints, thereby limiting the benefits of these systems to the wholesale market and other parts of the electricity market.

DOEs provide a DSO with flexibility to better manage network constraints and congestion compared to static network limits, which includes both import and export limits. DOEs allow a DSO to restrict VPP and EV operation in a more targeted way, for example by only limiting exports during periods of observed or anticipated localised network constraint. DSO information systems provide the data necessary to monitor network conditions, and so adjust any operational limitations accordingly. Practically, DOEs allow VPPs and EVs to operate more freely compared to static network limits, thereby providing a greater opportunity for those CER systems to engage in wholesale market arbitrage. While the analysis undertaken in this report focuses solely on DOEs for customer exports, a DOE may also provide flexible import limits for customers, providing additional DSO flexibility to manage network constraints and limits.

Similar to DOEs, dynamic pricing allows DSOs to more closely tailor network tariffs to the specific constraint conditions of the network. While time-of-use tariffs provide more cost reflective network tariffs, and so better price signals, compared to flat tariffs, dynamic pricing provides an even better price signal, which is more closely aligned to network constraints. It follows that dynamic pricing also results in VPPs and EVs participating more freely in wholesale markets, thereby providing these systems capability to engage in wholesale market arbitrage.

For both DSO capabilities, the benefits result from an improved operation and participation of VPPs and EVs in the wholesale market, which assists with avoiding wholesale market costs over the long term.

Estimated benefits from Distribution System Operator investment

To estimate the wholesale electricity market benefits of DSO investments, we have modelled the behaviour of a representative VPP and EV connected to the grid, charging and discharging to the network to arbitrate wholesale market prices under two cases, namely:

- a base case absent investment in DSO capabilities, where Ausgrid imposes static network limits and continues with time-of-use network tariffs as the number of CERs connected to the grid increases over time; and
- a factual case, where Ausgrid invests in DSO capabilities and so makes DOEs and dynamic pricing available to VPPs and EVs.

The total market benefits are estimated as the avoided wholesale market costs achieved through the charging and discharging of a representative VPP and EV, valued at the customer export curtailment value (CECV) as estimated by the Australian Energy Regulator (AER). We expected the use of the CECV to be a conservative estimate of the market benefits due to the exclusion of longer-term costs, such as avoided generation capacity investment, in the CECV estimate.

The benefits per VPP and EV are then scaled up for the entire Ausgrid network based on:

- projections of the number of VPPs and grid connected EVs operating within Ausgrid’s network over the modelling time horizon; and
- uptake scenarios for dynamic services by batteries and EVs, which we assume:
  - uptake of VPPs and EVs is 50 per cent;[1] and
  - DOEs and static limits would gradually be introduced in congested parts of the network.

The behaviour of the VPP and EV under the base case and factual case have been modelled using a dynamic optimisation model of a grid connected battery, given expectations about future wholesale electricity prices. Inputs and assumptions used for this analysis have been based on information consistent with the Australian Energy Market Operator’s (AEMO’s) Step Change scenario for the 2023 Inputs, Assumptions and Scenarios Report (IASR).

[1] Our previous report from February 2023 included analysis over a range of uptake assumptions between 25 and 75 per cent. This analysis indicated that the benefits on a per VPP and per EV basis were identical across these scenarios and therefore total benefits were linear in the uptake assumption, eg, the benefits in the 25 per cent uptake scenario are approximately half of the benefits in the 50 per cent uptake scenario. For simplicity, we present the results for the 50 per cent uptake scenario only.

Using this framework and the assumptions above, we estimate that the total wholesale electricity market benefits of DSO investments for VPPs and EVs in the Ausgrid network between FY2030 and FY2044 to be:

- approximately $43.5 million (real $2024, present value) following the implementation of dynamic pricing only;
- approximately $15.8 million (real $2024, present value) following implementation of DOEs only; and
- approximately $56.4 million (real $2024, present value) following the implementation of both DOEs and dynamic pricing.

Table E.1 provides a summary of the estimated wholesale market benefits by VPP and EVs, assuming a 5 kW static export limit and a 50 per cent uptake assumption for dynamic services.

Table E.1: Estimated wholesale electricity market benefits of DSO investments (real $2024, present value)

DSO capability	Virtual power plants	Grid connected electric vehicles	Total
Benefits of dynamic pricing only	*$11.8 million*	*$31.7 million*	*$43.5 million*
Benefits of DOEs only	*$6.7 million*	*$9.2 million*	*$15.8 million*
Benefits of dynamic pricing and DOEs	*$14.2 million*	*$42.2 million*	*$56.4 million*

Note: total column may not sum across rows due to rounding.

We have also estimated the wholesale market benefits on a per installed household battery system (assuming an average 7 kW battery for a household participating in a VPP) and per connected EV. Table E.2 provides a summary of the estimated wholesale electricity market benefits per household battery and EV on a per year basis.

Table E.2: Estimated wholesale electricity market benefits of DSO investments per household battery and electric vehicle (real $2024, present value)

DSO capability	Household battery	Electric vehicle
Benefits of dynamic pricing only	*$13.0 per battery per year*	*$87.4 per EV per year*
Benefits of DOEs only	*$5.2 per battery per year*	*$19.3 per EV per year*
Benefits of dynamic pricing and DOEs	*$15.1 per battery per year*	*$110.6 per EV per year*

1. Introduction

Australia's electricity markets are going through a period of fundamental change as they transition from a centralised system of large fossil fuel generation to a renewable energy future. Consumer energy resources (CERs) such as rooftop solar photovoltaic (PV), community batteries and electric vehicles (EVs), are expected to play an increasingly important role.

The increasing uptake of CERs presents a challenge for distribution network service providers (DNSPs). To maximise the beneficial impact of CERs, DNSPs will need to develop improved operating and pricing practices to better integrate these resources into the network.

Practically, this requires DNSPs to transition from being a traditional Distribution Network Operator (DNO) to a Distribution System Operator (DSO) to facilitate the development of dynamic network management practices such as dynamic network prices and dynamic operating envelopes (DOEs). With these capabilities, a DSO will have visibility of real-time conditions of the distribution network, which is then used to inform signals sent out to customers in the form of prices and export limits to incentivise improved use of CERs.

The investments required to transform a DNSP into a DSO are referred to in this report as DSO investments. This report focuses on two capabilities enabled by DSO investments: dynamic network prices and DOEs.

It is within this context that Ausgrid has engaged HoustonKemp to estimate the broader, non-network economic benefits of planned investments to build its capabilities as a DSO, which are an essential input to implementing DOEs and dynamic pricing across Ausgrid's network. We understand that these investments are to be included in Ausgrid's CER integration strategy for the 2024-29 regulatory control period.

The focus of our analysis is on estimating wholesale electricity market benefits of DOEs and dynamic pricing as it impacts on the operation of:

- virtual power plants (VPPs) in the wholesale market; and
- EVs charging and discharging to the network.

For the remainder of this report any reference to an EV refers to an EV capable of exporting to the grid, when required. It is these smart EV charging systems that are expected to benefit the most from DSO capabilities, both in aggregate and on a per unit basis.

We note that this report is an update to a previous report, provided to Ausgrid in February 2023. There are a number of assumptions underpinning the analysis undertaken in this report that have been changed relative to the previous analysis, most notably relating to the applicable tariffs and profile of dynamic export limits. In addition, the avoided wholesale market costs quantified in this analysis has been valued at the customer export curtailment value (CECV) estimates rather than the wholesale price.

Importantly, in our opinion the CECV undervalues the most likely market benefits of DSO investments, because the AER's methodology only includes the value from avoided fuel and variable operating costs in its estimate. To the extent that DSO investments contribute to the avoidance or delay in the need for large scale generation or transmission investments, which is not currently captured in the CECV estimate. It follows that the market benefit estimates included in this report are expected to be relatively conservative.

This report sets out the findings of our analysis in detail. The remainder of this report is structured as follows:

- section 2 describes the need for DSO investments in detail as well as the scope of DSO investments planned by Ausgrid;
- section 3 discusses the capabilities enabled by DSO investments;
- section 4 sets out the approach to quantifying wholesale market benefits arising from DSO investments as well as our estimates of the wholesale market benefits in the case studies of VPPs and EVs; and
- section 5 discusses other benefits arising from DSO investments, which include frequency control ancillary services (FCAS) benefits and network benefits.

Appendix A1 sets out the results of our sensitivity analyses.

2. The need for Distribution System Operator investments to support consumer energy resources

This section discusses the need for DSO investments to support the energy transition and facilitate CER integration, and the DSO investments that are planned by Ausgrid.

2.1 The need for Distribution System Operator investments

Australia's electricity markets are going through a period of fundamental changes as they transition from a centralised system of large fossil fuel (coal and gas) generation to a renewable energy future where demand for electricity is met through a combination of large-scale renewable energy, energy storage, demand management and CERs.

CERs, including rooftop solar PV, community batteries and EVs, are expected to play increasingly key roles in future energy markets. CERs are expected to contribute to energy generation, storage, demand flexibility and ancillary services, which in turn will reduce the total costs of energy for all consumers when compared with the business-as-usual scenario.

The introduction of CERs to the grid is a fundamental shift for networks built for uni-directional energy flows from large thermal generators to households. With CER the grid needs to be capable of supporting bi-directional flows, where consumers can withdraw electricity from, and export electricity to, the grid.

This transformation has also changed how consumers interact and participate in the electricity market. For example, rooftop solar PV allows households to generate electricity, whereas EVs, VPPs and community batteries facilitate the storage of electricity for use at another time and potential discharge back to the grid.

The decarbonisation, decentralisation and digitalisation of the grid mean that DNSPs need to reconsider their current business model, roles and capabilities and how they evolve to become DSOs. This also includes considering how to ensure the distribution network continues to operate in a reliable and efficient manner in the future, when there are high levels of CERs.

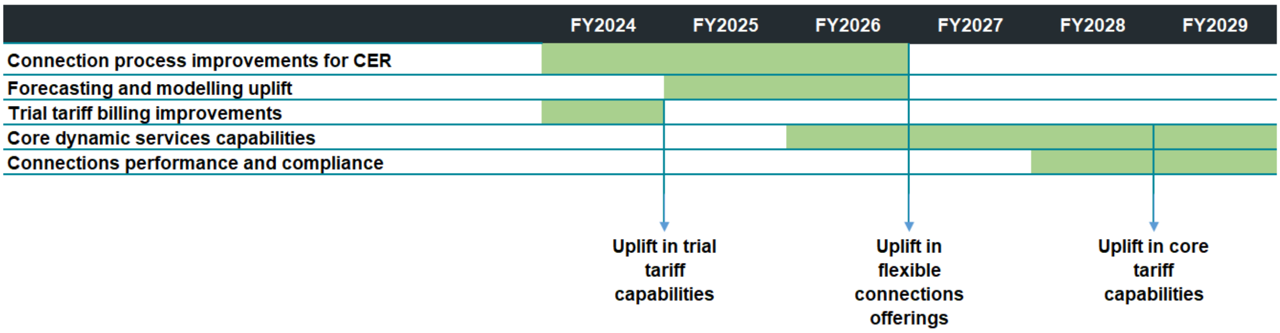
2.2 DSO investments planned by Ausgrid

To transition towards a DSO, Ausgrid is proposing to undertake investments during its 2024-2029 regulatory period to:

- improve connections processes for CER;
- build forecasting and modelling capabilities to better understand network hosting capacity and limits;
- enable dynamic operating envelopes (DOEs), and develop a standards-based network interface;
- upgrade billing and pricing capabilities, including creating the capability to implement dynamic network pricing; and
- improve connection performance and compliance.

Figure 2.1 provides an overview of the anticipated timing of these capabilities. A more detailed description of the capabilities gained from DSO investments is contained in Ausgrid's CER integration strategy.

Figure 2.1: Proposed timing of Ausgrid's Distribution System Operator capability improvements



Source: information provided by Ausgrid.

3. Capabilities enabled by DSO investments

To estimate the benefits of Ausgrid's planned DSO investments, we have focused on two capabilities that will be enabled by these investments, namely:

- dynamic operating envelopes (DOEs); and
- dynamic pricing.

In this section, we set out how the introduction of DOEs and dynamic network pricing leads to economic benefits.

3.1 Dynamic operating envelopes

3.1.1 The situation without DSO investments – static export limits

Electricity networks were built before the advent of CER and so were not specifically designed to support the two-way flow of energy. The increase in the number of CER technologies connected to the grid over the last ten years, and in particular the uptake of rooftop solar PV, has created several challenges for DSOs. These challenges result principally from the localised export of energy to the grid. The main challenge arises in circumstances where the amount exported exceeds the amount that can be supported by the local network.

The key grid problems from increasing localised exports include:

- potential for a rise in voltage levels, which leads to power quality problems; and
- challenges in managing the security of power supplies, which can result in network outages.

One way to manage the challenge of exports exceeding the capacity of the network is to impose static network limits on both imports and exports. In particular, static export limits on consumers with CERs can be a particularly useful approach in managing network constraints. A static export limit involves setting a fixed level of exports, typically measured in kilowatts (kW), that a consumer cannot exceed at any point in time. As this is a fixed limit, it restricts how much consumers can export even during periods when the network is not constrained or when the network would benefit from a higher level of exports.

South Australia Power Network (SAPN) is an example of a distribution network business that has imposed static export limits for its customers. SAPN has imposed a static limit of 5 kW on exports since 2017 in response to high levels of uptake of solar PV systems.[2] SAPN has since imposed more restrictive static export limits in congested parts of its network, which we describe further in section 3.1.2 below.

Ausgrid currently does not impose any export limits.[3] However, we understand that the anticipated increase in uptake of CER within its network will likely mean that Ausgrid will eventually need to manage the amount that is exported by CERs into the grid. In the absence of DSO investments, Ausgrid will likely need to impose static network limits in areas where the network is constrained.

[2] SA Power Networks, *Clarification regarding small embedded generation requirements*, available at https://www.sapowernetworks.com.au/data/9972/clarification-regarding-small-embedded-generation-requirements/, accessed 7 November 2023.

[3] We note that an export limit, which restricts export capacity at a connection point, is distinct from a basic export level, which is defined at clause 11.141.12 of the National Electricity Rules.

3.1.2 The situation with DSO investment – dynamic limits apply only when the network is constrained

In contrast to static network limits, dynamic operating envelopes (DOEs) consist of flexible import and export limits that vary over time and location based on the hosting capacity of the local distribution network. DSO investment provides Ausgrid with visibility on the real-time condition of the network, thereby allowing a move away from fixed limits to dynamic limits. It follows that DOEs allow Ausgrid to impose limits only when the hosting capacity of the network is constrained, eg, when there are large exports from rooftop PVs and demand for electricity is low.

In most time periods, the network is not expected to be constrained. It follows that in most time periods, consumers should be able to export electricity to their full capacity without any administrative network limits[4]. DOEs allow CERs to operate without any network limits during most time periods, thereby allowing CERs to provide additional value to the market. This additional flexibility to operate provides benefits to the market, eg, by enabling more renewable energy generated on the distribution network to be exported to the grid, which reduces demand from grid-scale generation and so lowers wholesale electricity costs for all consumers in the NEM.

Assessing the benefits of moving from static network limits to DOEs requires the definition of an appropriate base case, ie, what static limits would apply if DSO investment did not occur, and project case, ie, how would DOEs operate within Ausgrid's network. There is uncertainty regarding what network limits would apply with and without DSO investment. For the purposes of this analysis, we have assumed that:[5]

- without DSO investment, Ausgrid would need to gradually impose a 5 kW static export limit in congested parts of the network; whereas
- with DSO investment, Ausgrid could implement DOEs in which:
  - a 5 kW export limit would be gradually introduced in congested parts of the network; but
  - this export limit would only be applied to the top 10 per cent of high-priced periods in the wholesale market.

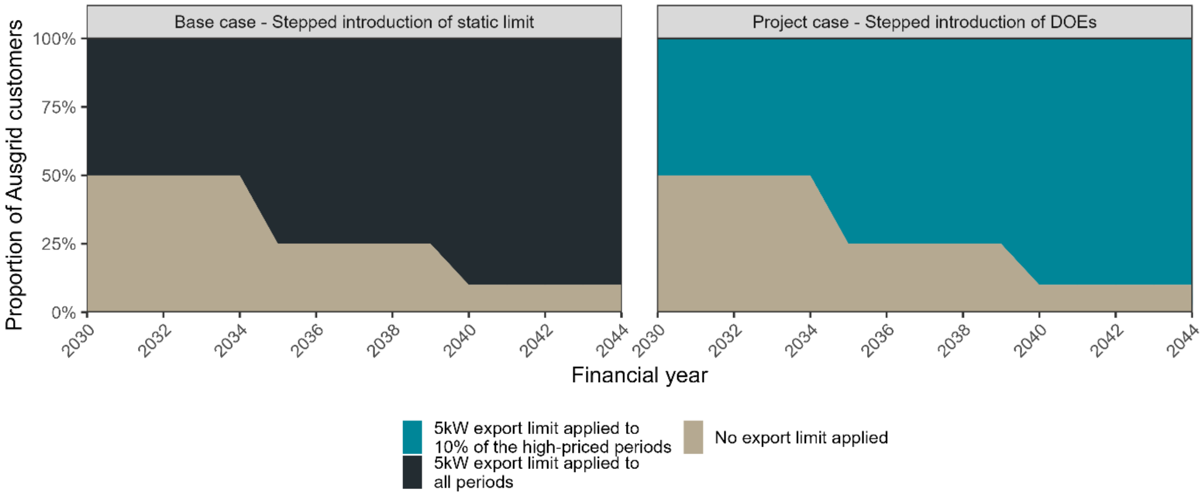
While DOEs are defined as flexible limits for both imports and exports, the analysis undertaken in this report focuses solely on the flexible export limit dimension of DOEs.

Figure 3.1 below demonstrates the proportion of Ausgrid's customers who will be subject to fixed or dynamic network limits over time.

[4] Note that exports will still be subject to physical fuse limits. It follows that references throughout the report to 'without limit' should be taken to mean no limits apart from the physical fuse limit.

[5] In light of current uncertainty regarding the appropriate magnitude of an export limit, we have conservatively assumed the upper bound of Ausgrid's proposed options, ie, 5 kW. We consider the implications of a lower export limit on the wholesale market benefits of DSO investment in appendix A1.

Figure 3.1: Assumed proportion of customers subject to static or dynamic export limits over time



Source: information provided by Ausgrid.

SAPN is an example of a DSO that has implemented DOEs. Since September 2021, SAPN has classified certain substation zones in its metropolitan distribution network as congested.[6] These substation areas have a high penetration of rooftop solar PV and are reaching the limit of solar export hosting capacity during certain time periods of the year. Customers connecting new solar or upgrading their systems in these areas are given the following two choices:[7]

- a fixed export limit of 1.5 kW per phase; or
- a dynamic export limit, which varies between 1.5 kW and 10 kW.

As of June 2022, customers on dynamic export limits have been provided with a 10 kW export limit for 100 per cent of the time so far, but this is expected to decrease to 98 per cent over the congested spring months.[8]

To understand the impact of different static export limits on this analysis, we have modelled additional scenarios with lower static export limits, ie, 3 and 1.5 kW, with the results of these scenarios presented in appendix A1. These additional scenarios have been modelled to capture the uncertainty surrounding the magnitude of an export limit that Ausgrid may implement and indicate that the wholesale market benefits of DSO investments increase significantly when export limits are lower.

3.2 Dynamic network pricing

3.2.1 Situation without DSO investment – existing network tariffs continue to apply

Cost reflective tariffs are expected to improve economic efficiency as they provide consumers with price signals that more accurately reflect the costs of providing services. Given this, over the past decade or so, network distribution businesses have been transitioning away from flat usage-based tariffs towards more cost reflective network tariffs, such as time-of-use (ToU) tariffs and demand tariffs.

[6] SA Power Networks, *Flexible Exports for Solar PV – Lessons Learnt Report 4*, 23 June 2022, p 4.

[7] SA Power Networks, *Flexible Exports for Solar PV – Lessons Learnt Report 4*, 23 June 2022, p 4.

[8] SA Power Networks, *Flexible Exports for Solar PV – Lessons Learnt Report 4*, 23 June 2022, p 17.

Having tariffs that are more cost reflective will become increasingly important in the future as the number of price responsive devices, such as batteries and EVs, are expected to become more prevalent within Ausgrid's network.

While ToU and demand tariffs are more cost reflective than previous flat usage-based tariffs, these tariffs do not reflect real-time, or close to real-time, changes in actual network conditions. It follows that dynamic network prices, which provide greater flexibility to align prices with network constraints – which are inherently dynamic in nature – would be more cost reflective compared to existing ToU and demand tariffs.

However, Ausgrid's existing pricing and billing systems are not well equipped to support the creation and implementation of more dynamic and complex network pricing structures and trialling of innovative tariffs. In other words, without DSO investment, Ausgrid will not be able to implement more dynamic, cost reflective network tariffs in the future.

3.2.2 Situation with DSO investments – ability to introduce dynamic network prices

Dynamic network pricing capabilities enable network operators to set tariffs that can change in response to real-time network conditions. For example, network operators can set a high network price for exporting electricity into the grid when the network is export constrained, when there are high levels of solar PV output but low levels of demand. Similarly, dynamic network prices allow network operators to set network prices for exporting electricity to zero or very low levels when the network has an abundance of export capacity.

To understand the potential benefits that could arise from the introduction of dynamic prices, Ausgrid is currently undertaking a trial of these tariffs, called Project Edith, with an aim to explore the use of innovative tools, such as dynamic network prices.[9] It is expected that dynamic network prices will change how retailers or aggregators operate a VPP.

The dynamic network tariffs being tested in Project Edith change based on the time-of-day and weather conditions, which are reasonable indicators of whether the network is likely to be constrained. For instance, on a sunny mild day the import tariff during the middle of the day may be cheaper, to incentivise the charging of a battery or EV from excess distributed and/or utility-scale solar generation. However, on a warm cloudy day, higher air conditioning demand and a reduction in distributed and/or utility-scale solar generation may give rise to a relatively tight supply and demand balance on the network and higher import tariff in the late afternoon and early evening.

For the purposes of this analysis, we have assumed that:

- without DSO investments, Ausgrid would continue to implement the existing ToU tariff from its 2024-29 regulatory period going forward, as shown in table 3.1 below; whereas
- with DSO investments, Ausgrid would apply dynamic network prices for price responsive devices such as VPPs or EVs, as shown in table 3.2 below.

[9] For more information, please see: Ausgrid, *Project Edith*, available at https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith, accessed 7 November 2023.

Table 3.1: Time of use network tariff assumptions

Tariff component	Applied periods	Units	Imports	Exports
Fixed charge	**All days**	*c/day*	*52.12*	-
Import peak	**3pm to 9pm every day between November to March and June to August**	*c/kWh*	*25.90*	-
Export reward	**4pm to 9pm every day**	*c/kWh*	-	*-2.26*
Export peak	**10am to 3pm every day**	*c/kWh*	-	*1.21*
Off-peak	**All other times***	*c/kWh*	*4.06*	*0.00*

Source: charging windows for EA025 (import tariff) and EA960 (export tariff) from Ausgrid's Tariff Structure Statement Compliance Document 2024-29, January 2023, pp 20 and 22, submitted as part of Ausgrid's draft regulatory proposal; and tariff charges taken for the 2024-25 financial year from Ausgrid's Indicative pricing schedule – NUOS, January 2023, submitted as part of Ausgrid's draft regulatory proposal.
*Note: * the off-peak period applies for imports at all times other than those covered by the import peak period and applies for exports at all times other than those covered by the export peak and export reward periods.*

Table 3.2: Dynamic network tariff schedule assumptions

Tariff component	Applied periods	Units	Imports	Exports
Fixed charge	**All days**	*c/day*	*48.90*	*48.90*
Import peak	**5pm to 9pm when temperature <10ºC or >26ºC**	*c/kWh*	*98.10*	*-98.10*
Export peak	**10am to 2pm when wholesale price in this period is in the lowest 50% of days for the year**	*c/kWh*	*0.00*	*1.85*
Off-peak	**All other times**	*c/kWh*	*0.50*	*0.00*

Source: information provided by Ausgrid.

We understand that prices developed for Project Edith are very early tests of weather-based pricing. It follows that dynamic network prices will likely evolve over time and so the dynamic network prices we have assumed are unlikely to align with prices that are implemented in the future. Notwithstanding, we expect that the assumptions we have made allow for a reasonable sense-of-magnitude estimate of the benefits that will likely arise from introducing dynamic network prices.

Network tariffs lead to significant changes in the operation of price responsive devices. By way of example, under Ausgrid's ToU tariff for residential customers (EA025) during the 2021-22 financial year, the network prices for imports was 25.4 cents per kWh during peak periods,[10] or $254 per MWh. This compares against the range in wholesale electricity prices in NSW in the 2021-22 financial year where approximately 85 per cent of 5-minute wholesale electricity prices between 2pm and 8pm[11] were in the range of $30 to $300 per MWh.[12] It follows that there is a very strong network price signal for batteries to avoid charging during peak periods, even when the network is not constrained and wholesale prices are low.

[10] Ausgrid, *Pricing Proposal for the financial year ending June 2022*, March 2021, p 12.

[11] The peak period for EA025 in the 2021-22 financial year was 2pm and 8pm in November to March. See: Ausgrid, *Attachment 10.01 – Tariff Structure Statement*, April 2019, p 17.

[12] HoustonKemp's analysis of wholesale electricity prices in NSW provided by AEMO in the Market Management System (MMS) Data Model.

In practice, we expect that batteries would charge during the daytime, eg, between 10am to 2pm, when solar output is high and wholesale prices are low and discharge during the evening, eg, 5pm to 9pm, when solar generation is low and wholesale prices are high. To illustrate the barrier created by network prices, we consider the wholesale market prices observed during December 2021. In this month, the average wholesale market spot price was around:[13]

- $49 per MWh between 10am to 2pm; and
- $93 per MWh between 5pm to 9pm.

The price difference of $44 per MWh between the two periods is lower than the shoulder network tariff of $56.2 per MWh,[14] which would have applied if the battery charged during the day.[15]

Network tariffs can act as a barrier for batteries supporting the wholesale market as the benefits from charging and discharging, ie, wholesale market arbitrage, need to be larger than any applicable network charge. Put another way, the difference in wholesale market prices between time periods need to be larger than the network charge for there to be an arbitrage opportunity, otherwise the battery would make a loss during these periods and would therefore be better off not charging and discharging. Further, it follows that the move from ToU network tariffs to dynamic network tariffs where prices are very low in most time periods means that batteries can arbitrage the wholesale market under more circumstances, thereby delivering more wholesale market benefits.

We note that Ausgrid's proposed residential ToU tariff (EA025) for the 2024-29 regulatory control period will improve the wholesale market arbitrage opportunity for grid connected batteries relative to previous specifications of this tariff. In particular, Ausgrid has proposed to remove the shoulder charge and include this period as part of the off-peak period with lower import charges ($40.6 per MWh),[16] and has proposed to implement an export tariff that rewards exports during the import peak period ($22.6 per MWh). This results in the net cost of importing in the middle of the day and exporting during the evening being significant lower under the proposed future ToU tariffs (a $40.6 per MWh cost for charging less a $22.6 per MWh reward for discharging) relative to previous ToU tariffs (a $56.2 per MWh cost for charging with no reward for discharging).

ToU tariffs and dynamic tariffs provide aggregators with different pricing incentives for charging and discharging. Under a ToU tariff, network prices provide aggregators with a financial incentive to:

- charge during off-peak periods as import network prices are lowest ($40.6 per MWh); and
- avoid charging during peak periods (3pm to 9pm in November to March and June to August) as import network prices are highest ($259 per MWh).

In contrast, dynamic network tariffs provide the following financial incentives:

- a very low price for charging ($5 per MWh) and a zero price for discharging during off-peak periods, ie, when the network is unconstrained, which helps align charging and discharging behaviour with wholesale market price signals;
- an incentive to charge (zero price) and disincentive to discharge ($18.5 per MWh) during export peak periods, reflecting the low level of demand and high level of distributed and utility-scale solar generation during these times; and
- a very strong price incentive to discharge rather than charge during import peak, as aggregators are paid $981 per MWh to discharge and need to pay $981 per MWh to charge during these periods.

[13] HoustonKemp's analysis of wholesale electricity prices in NSW provided by AEMO in the Market Management System (MMS) Data Model.

[14] Ausgrid, *Pricing Proposal for the financial year ending June 2022*, March 2021, p 12.

[15] Ausgrid, *Attachment 10.01 – Tariff Structure Statement*, April 2019, p 17.

[16] Ausgrid, *Our TSS Explanatory Statement for 2024-29*, January 2023, p 32.

4. Wholesale electricity market benefits of DSO investments

Benefits of DSO investments include both wholesale electricity market benefits and network benefits. Our analysis focuses on the estimation of incremental wholesale electricity market benefits arising from changes in the operation of VPPs and EVs, through the implementation of DOEs and dynamic pricing.

A VPP is a group of individual CERs, such as solar PV and batteries, which are connected to the network in different locations. An aggregator can coordinate these individual CERs so they can participate in trading in the wholesale electricity market and provide network services and grid support.

Similarly, some EVs will be capable of discharging to the network and so participating in trading in the wholesale electricity market. However, unlike VPPs, EVs are used principally for transport, and so:

- may not be available to trade in the wholesale electricity market at all times; and
- need to charge for transport purposes and reduce the volume of stored electricity when used for transport.

This section sets out the framework used to estimate wholesale electricity market benefits of DSO investments for VPPs and EVs.

4.1 How DOEs and dynamic pricing delivers wholesale electricity market benefits

Wholesale electricity market prices are set by market conditions and can vary significantly between different time periods. For example, wholesale electricity market prices are likely to be low or even negative when the supply of electricity from renewable sources is high and demand for electricity from consumers is low.

Variability in wholesale market prices provide aggregators an opportunity to arbitrage the difference in prices over time. For example, aggregators can charge a VPP when wholesale prices are low and discharge when wholesale prices are high. The price difference provides aggregators with a financial incentive to actively participate in the wholesale market. Doing so may also reduce wholesale market costs as wholesale market prices reflect the cost of dispatching the marginal generator, which may be lower when distributed generation displaces some wholesale market generation.

Static network limits restrict the participation of VPPs and EVs in the wholesale electricity market as it places a fixed limit on how much a battery can import and/or export. These limits are set at a level that assists network businesses to manage network congestion at ‘critical peaks’ during the year. It follows that static network limits are set with the ‘worst case scenario’ in mind but apply even when network is unconstrained. In contrast, DOEs allow distribution network providers to apply export or import limits when required by the network, ie, VPPs are not restricted when the network is unconstrained, thereby allowing VPPs to participate in the wholesale market more freely.

Similarly, existing ToU tariffs can distort the incentive for VPP and EV participation in the wholesale electricity market. Aggregators maximise the revenue obtained from their fleet of CER given the wholesale market price and network prices. As such, network tariffs affect the behaviour of VPPs and EVs. However, existing ToU tariffs are less cost-reflective when compared to dynamic network prices and so can distort the operation of VPPs and EVs. Given this, the introduction of more dynamic and cost reflective network prices will promote the more efficient use of these CER devices.

Table 4.1 provides the benefit logic map for how the introduction of DOEs and dynamic network prices can lead to wholesale electricity market benefits.

Table 4.1: Benefit logic map for wholesale energy benefits

	Base case VPP and EV operation	DSO investments	Capability enabled by the DSO investments	Change in VPP and EV operation	Benefits
Network limits	Static network limits do not reflect actual network conditions and restricts the ability of VPPs and EVs to participate in the wholesale market	Forecasting and modelling uplift DOEs and standards-based interface	DOEs	Aggregators face less restrictions when operating VPPs under DOEs	Reduced wholesale electricity costs
Network tariffs	Aggregators maximise revenue obtained from VPPs given wholesale market prices and ToU tariffs ToU tariffs affect behaviour of VPPs, but are less cost reflective when compared to dynamic prices This results in sub-optimal use of VPPs	Forecasting and modelling uplift Billing and pricing	Dynamic pricing	Aggregators maximise revenues obtained from VPPs given wholesale market prices and dynamic network prices Dynamic network prices are more cost-reflective than ToU tariffs This results in improved use of VPPs	Reduced wholesale electricity costs

4.2 Quantification framework of wholesale electricity market benefits

Our framework for quantifying wholesale electricity market benefits involves estimating the change in the timing and quantity of both charging and discharging of VPPs and EVs, valued at the CECV in the respective 30-minute time period. This reflects the role that participation of VPPs and EVs in the wholesale market plays in avoiding wholesale market costs.

Practically, this benefit is calculated by:

- first, determining the change in the quantity discharged and charged between the ‘without’ and ‘with’ DOE and dynamic pricing scenarios for every 30-minute interval for each day of the modelling horizon;
- second, multiplying the change in quantity discharged and charged, by the CECV in that 30-minute interval; and
- third, subtracting the wholesale market cost of VPP and EV operation incurred by charging in each 30-minute interval, ie the change in quantity charged multiplied by the CECV, from the wholesale market cost of VPP and EV operation avoided by discharging in each 30-minute interval, ie, the change in quantity discharged multiplied by the CECV.

The result reflects the net costs avoided from the wholesale market as a consequence of the change in operational behaviour of a VPP or EV, due to the implementation of DOEs and/or dynamic prices.

We explain in section 4.2.1 the interaction between the forecast wholesale electricity price, which is used as part of the financial incentives to determine VPP and EV operation, and the CECV, which is used to quantify the economic cost impact of this VPP and EV operation.

To estimate how a VPP or EV will change its charging and discharging pattern with and without DSO investment, we have used a battery modelling tool previously developed by HoustonKemp for Ausgrid. The battery model provides insights into when and to what extent a battery, which may participate in a VPP or be an EV with vehicle-to-grid export capabilities, would charge and discharge in response to wholesale electricity prices and network tariffs, eg, charging when prices are low and discharging when prices are high, such that total revenue is maximised subject to various constraints including network limits, round-trip battery efficiency, storage performance degradation and cycling constraints.

We set out key features of the battery modelling suite in section 4.2.2 below.

We describe the key modelling inputs, assumptions and parameters that relate to our battery modelling suite in section 4.2.3 below, with more detailed assumptions relating specifically to the application of the battery model to VPPs and EVs contained in sections 4.3.1 and 4.4.1 respectively.

4.2.1 Use of wholesale electricity prices to simulate VPP and EV operation

Our battery modelling framework simulates profit maximising behaviour from a battery operator in response to financial costs and benefits, ie, the wholesale electricity price paid or received and the applicable network tariff (which may be a charge or a network service payment). Customers typically receive a retail tariff that passes through the network price signal, with some additional components relating to wholesale electricity costs, other retail costs and a retail margin. However, given that a VPP operator (or an orchestrated EV aggregator) will likely be the battery owner's retailer, the retail-specific components of the network tariff will not be applicable to the financial price signals faced by the battery. As such, the appropriate price signals to simulate battery operation is the combination of the wholesale market price and the network tariff.

To obtain a forecast of future wholesale electricity prices, we:

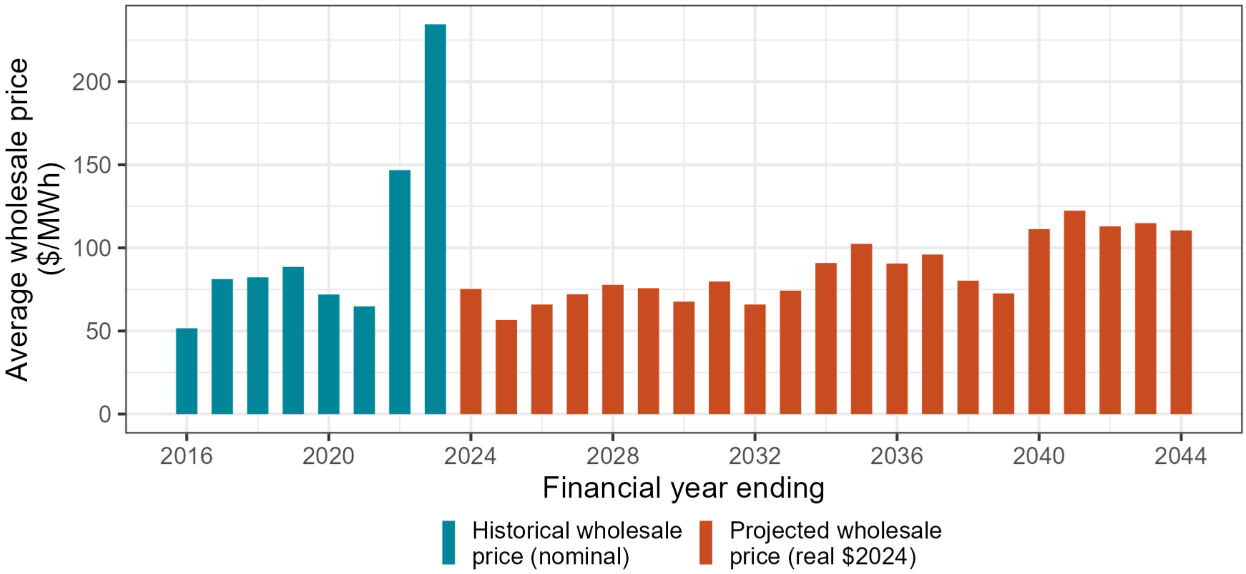
- obtain an estimate for wholesale electricity prices in the 2023-24 financial year by inflating historical wholesale electricity prices in the 2020-21 financial year to real $2024;[17] and
- extrapolate the estimate of wholesale prices in the 2023-24 financial year using the annual growth rate of wholesale electricity prices implied by the AER's CECV estimates.

It follows that using the growth rates implied by the CECVs allows us to factor these long-term dynamics of investments in the forecasts of wholesale electricity prices.

Figure 4.1 demonstrates our wholesale price forecast methodology. We note that the 2021-22 and 2022-23 financial years, ie, the two most recent completed years, experienced a number of significant events that substantially impacted the wholesale market price during these years. To avoid capturing the impact of these events in our analysis we have used the 2020-21 financial year as our base year. By inflating base year (2020-21 financial year) prices to real $2024, we are assuming that projected wholesale electricity prices in the 2023-24 financial year will be equal, in real terms, to historical wholesale electricity prices in the 2020-21 financial year.

[17] We assume inflation of 16.48 per cent between June 2021 and June 2024, which consists of 12.54 per cent inflation between June 2021 (CPI of 188.8) and June 2023 (CPI of 133.7) and a further 3.5 per cent forecast inflation between June 2023 and June 2024. See: Australian Bureau of Statistics, *6401.0 Consumer Price Index, Australia*, Series A2325846C; and Reserve Bank of Australia, *Statement on Monetary Policy*, August 2023, table 5.1, p 66.

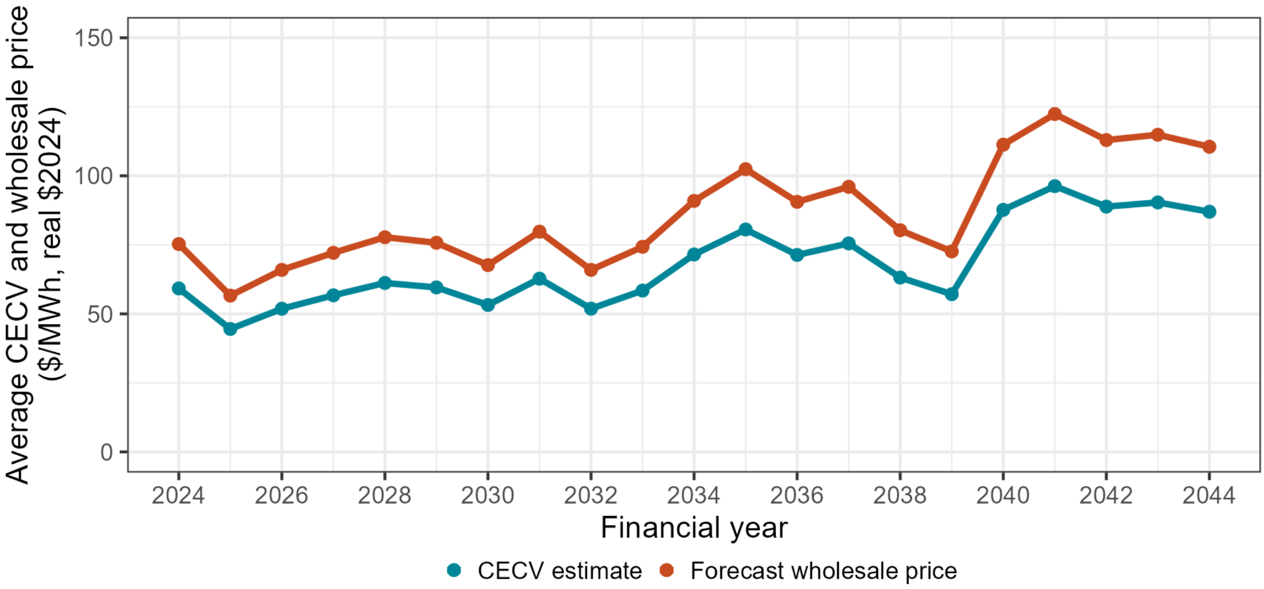
Figure 4.1: Comparison of historical and forecast wholesale electricity market prices



Source: HoustonKemp's analysis of wholesale electricity prices in NSW provided by AEMO in the Market Management System (MMS) Data Model; and CECV estimates from AER and Oakley Greenwood, CECV workbook – 2023.

Figure 4.2 presents the annual average wholesale electricity price projections used in our analysis, compared against the annual average CECV estimate. As described above, the forecast wholesale electricity price and the CECV have an identical profile of annual averages, since we calibrate the wholesale price projection to align with the annual growth rate in CECV.

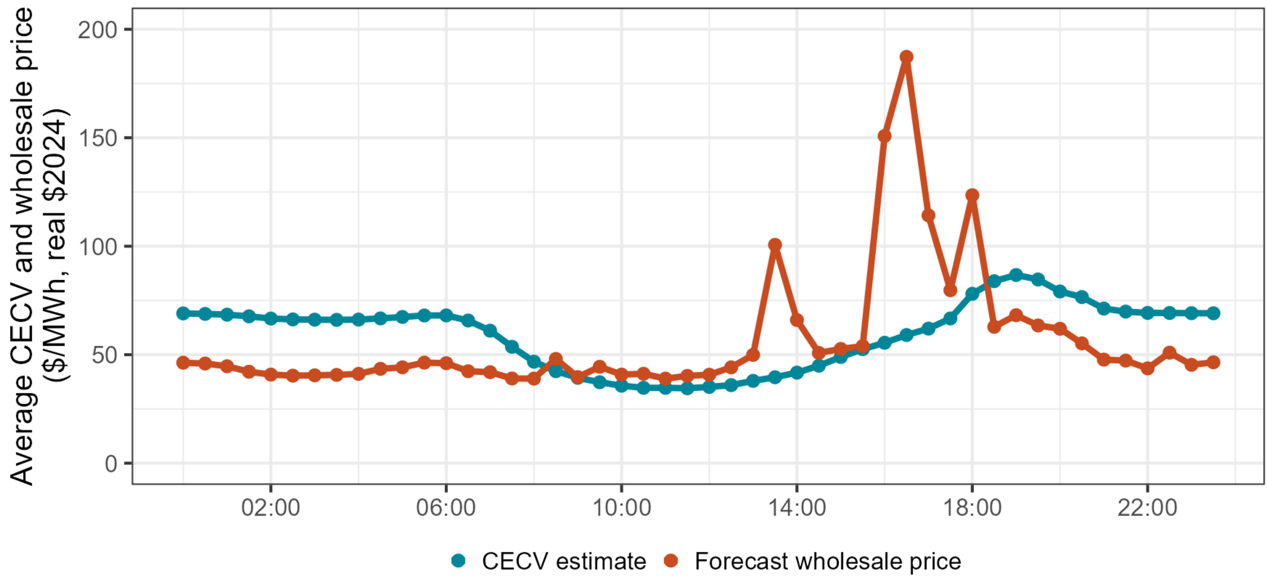
Figure 4.2: Annual average wholesale electricity price and CECV estimate



Source: CECV estimates from AER and Oakley Greenwood, CECV workbook – 2023.

Figure 4.3 provides a comparison of the average daily profile for the wholesale electricity price forecast and the CECV over the summer months of the 2024-25 financial year. We note that the wholesale price forecast displays more variation across the day than the CECV, with the CECV consistently higher than the wholesale price forecast during non-daylight hours.

Figure 4.3: Daily wholesale electricity price and CECV estimate for December 2024 to February 2025



Source: CECV estimates from AER and Oakley Greenwood, CECV workbook – 2023.

In our previous analysis, we used the wholesale electricity price to quantify the economic cost of VPP and EV operation. At the AER's request, we have performed this updated analysis using the CECV to value the impact on economic costs in the wholesale electricity market.

Wholesale electricity prices represent the equilibrium price at which the supply for electricity equals demand. It also represents the cost of dispatching the marginal generator into the wholesale market. In the long run, wholesale market electricity prices reflect the long run marginal costs of generating electricity. The long run marginal cost includes the cost of operating a generator, eg, fuel and maintenance costs, and the capital costs of investing in a generator. Wholesale market prices will in the long run reflect the long run marginal costs of supplying electricity because:

- if wholesale market electricity prices are higher than the long run marginal costs of generation, then there would be an incentive for investors to invest additional generation to make a profit; and
- if wholesale market electricity prices are lower than the long run marginal costs of generation, then there is a disincentive for investors to invest in additional generation.

Given the above, we maintain that the wholesale electricity price is the appropriate value to use in estimating these market benefits because, in the long run, market prices will reflect the long run marginal costs of generation. In using the CECV, which only quantifies the short-run dispatch costs of the wholesale electricity market, we expect the results in this analysis to conservatively underestimate the likely actual benefit of DSO investment in the wholesale market.

4.2.2 Battery modelling to estimate the change in charging and discharging behaviour

As discussed above, we define wholesale electricity market benefits as the avoided wholesale electricity costs resulting from incremental changes in operational behaviour of VPPs and EVs, once network capabilities have been delivered through DSO investments.

Our battery model uses optimisation techniques to draw insights into how a VPP or EV maximises total revenue earned by charging and discharging in response to wholesale electricity prices, network tariffs and network limits, subject to operating characteristics of the battery, ie, power, storage capacity and round-trip efficiency, etc.

Our battery model provides insights into the timing as well as quantity of electricity that a battery would draw from and inject into the grid. As our model is set up for profit maximisation, the battery will only charge if the net gains from discharging this stored capacity at some other time exceeds the costs incurred to store this energy, inclusive of any applicable network tariffs.

Specific to the case of EVs, the charging and discharging patterns of the battery are also subject to whether the EV is capable of discharging to the grid and is available and connected to the grid to provide this service, ie, EVs that are being driven on roads will not be available to discharge to the grid. In addition, electricity in an EV's battery will be drawn down as the EV is being used as a means of transport. We explicitly take these factors into account in our battery modelling of EVs.

Our battery model provides insight as to the wholesale electricity benefits delivered by an individual VPP, ie, a collection of batteries, or EV. We multiply this benefit for a single representative VPP or EV by the number of VPPs and EVs expected to benefit from DSO investment to calculate the associated wholesale electricity benefits across the entire fleet of these CER devices.

4.2.3 Description of key overarching modelling assumptions

Our analysis estimates wholesale electricity benefits between the 2029-30 and 2043-44 financial years. Where relevant, we have used assumptions from AEMO's step change scenario as set out in its 2022 Integrated System Plan (ISP) modelling.[18]

We present all costs and benefits in real $2024 terms, using historical inflation data from the Australian Bureau of Statistics and inflation forecasts from the Reserve Bank of Australia.[19]

We have been instructed by Ausgrid to use a 3 per cent discount rate to convert the stream of economic costs and benefits in the wholesale market over the evaluation period to 2023-24 financial year present value terms.

4.3 Estimating wholesale electricity benefits of DSO investments to VPPs

The wholesale electricity market benefits of DSO investments for VPPs are estimated by applying our battery model as described in section 4.2.2.

4.3.1 Key assumptions

We apply the following assumptions specific to the VPP case study in our analysis.

[18] This is consistent with the scenario that is being adopted by the majority of distributors for the purpose of planning forthcoming expenditure proposals.

[19] See: Australian Bureau of Statistics, *6401.0 Consumer Price Index, Australia*, Series A2325846C; and Reserve Bank of Australia, *Statement on Monetary Policy*, August 2023, table 5.1, p 66.

Characteristics of VPPs

Understanding the change in wholesale electricity as a consequence of additional battery participation requires an understanding of the number of batteries controlled by a VPP. Our analysis assumes there are 890 batteries in a VPP[20] with the following composition:[21]

- 40 per cent with power of 5 kW;
- 33 per cent with power of 7 kW; and
- 27 per cent with power of 10 kW.

Each battery is assumed to have storage capacity of 13.5 kWh and round-trip efficiency of 90 per cent.[22] Storage capacity is subject to degradation, with effective capacity decreasing gradually from 100 per cent in FY2030 to approximately 70 per cent in the 2043-44 financial year.

Altogether, one VPP has the following specifications:[23]

- power of 6,230 kW;
- storage capacity of 12,015 kWh; and
- round-trip efficiency of 90 per cent.

We have also assumed that 20 per cent of VPP capacity is reserved for other services provided by an aggregator, such as provision of FCAS market services, other ancillary services, other network support services and services to the consumer, eg, back up electricity in event of outage.

Projected number of VPPs connected to Ausgrid's network

We have projected the number of VPPs connected to Ausgrid's network based on AEMO's aggregated embedded energy storage forecasts (in MW). This is consistent with the assumptions of VPPs used by AEMO in its publication of the 2023 IASR and the modelling that underpins the 2022 ISP.[24]

To transform these forecasts into the number of VPPs within Ausgrid's network, we make the assumption that:

- 32 per cent of the number of VPPs in NSW would be connected to Ausgrid's network; and
- that each VPP is assumed to have a power of 6,230 kW, as discussed above.

We understand that not all VPPs in the network may make use of DOEs and take up dynamic prices. To account for uncertainty around adoption rates, we assume an adoption rate 50 per cent. In our previous analysis, we assumed a range of adoption rates, which indicated that total benefits were linear to the take-up rate, as the per unit benefits were constant across all uptake rates.

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[20] This assumption is based on the characteristics of VPPs participating in the AEMO's VPP demonstration programme. The programme includes eight VPP portfolios with approximately 7,150 consumers, ie, approximately 890 consumers per VPP. See: *AEMO, NEM Virtual Power Plant demonstrations – Knowledge sharing report number 4*, September 2021, p 4.

[21] We assume batteries in the model to have specifications of a Telsa's Powerwall. The disaggregation is to account for the fact that Powerwall has power of 5 kW if operating continuously, and that batteries are expected to become larger in the future. For details see: Tesla, *Powerwall*, available at https://www.tesla.com/en_au/powerwall, accessed 7 November 2023. We have estimated the assumed composition percentages to ensure that the average power of a VPP aligns with AEMO's assumptions from the 2022 ISP.

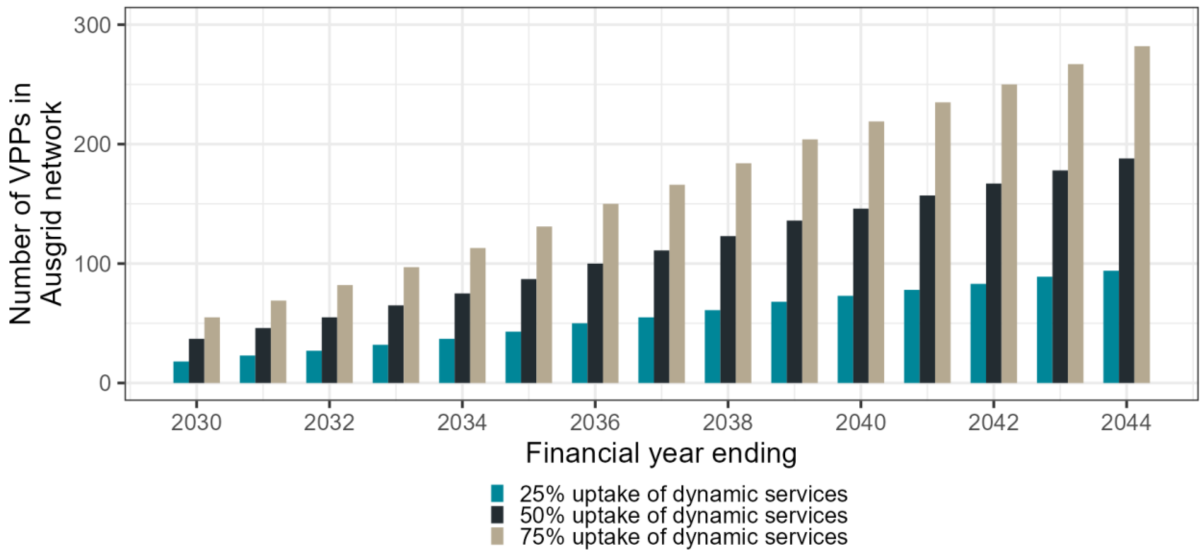
[22] Specifications of a Tesla's Powerwall. For details see: Tesla, *Powerwall*, available at https://www.tesla.com/en_au/powerwall, accessed 7 November 2023.

[23] Power and storage capacity of a VPP are assumed to be the combined power and storage capacity of 890 batteries in the VPP, which is consistent with AEMO's 2022 ISP.

[24] In the wholesale energy market modelling for the 2022 ISP, aggregated embedded energy storage systems are modelled like a VPP operated by a retailer/aggregator as an alternative supply source for arbitrage or emergency response.

Figure 4.4 presents the forecast number of VPPs in Ausgrid's network that would benefit from DSO investments over the modelling horizon. The forecast number of VPPs in Ausgrid's network is assumed to be the same in the 'without' and 'with' DSO investments scenarios. In other words, we have assumed that DSO investments does not increase the number of VPPs connected to Ausgrid's network.[25]

Figure 4.4: Forecast number of VPPs in Ausgrid's network, by uptake proportions, FY2030 to FY2044



Source: HoustonKemp adjustment of forecasts of aggregated embedded energy storage systems obtained from AEMO's 2023 inputs, assumptions and scenarios workbook.

4.3.2 Wholesale electricity market benefits results for VPPs

Starting from the base case where VPPs within Ausgrid's network are subject to stepped implementation of static network limits (as set out in section 3.1) and ToU prices, wholesale electricity market benefits of DSO investments for all VPPs in Ausgrid's network between the 2029-30 and 2043-44 financial years are estimated to be:

- $11.8 million (real $2024, present value) following the implementation of dynamic pricing only;
- $6.7 million (real $2024, present value) following the implementation of DOEs only; and
- $14.2 million (real $2024, present value) following the implementation of both DOEs and dynamic pricing.

On a per-battery and per-year basis, these wholesale electricity market benefits are equivalent to:

- $13.0 per battery per year (real $2024, present value) following the implementation of dynamic pricing only;
- $5.2 per battery per year (real $2024, present value) following the implementation of DOEs only; and
- $15.1 per battery per year (real $2024, present value) following the implementation of both DOEs and dynamic pricing.

A summary of estimated total wholesale market benefits are set out in table 4.2, with estimated annual benefits for each VPP also included in the table.

[25] Our analysis quantifies the benefits of DSO investments as the change in operational behaviour for a VPP over a fixed number of VPPs. As DSO investments will likely improve the private benefits for VPP operators and VPP participants, we anticipate that participation in VPPs, and therefore the number of VPPs on Ausgrid's network, will also increase. By not quantifying this effect, our estimate of wholesale market benefits for VPPs is likely to be conservative.

Table 4.2: Estimated wholesale electricity market benefits of DSO investments (real $2024, present value)

	Wholesale electricity market total benefits (real $2024, present value)	
DSO capability	**Total (FY2030 to FY2044)**	**Per device per year**
Benefits of dynamic pricing only	*$11.8 million*	*$13.0 per battery per year*
Benefits of DOEs only	*$6.7 million*	*$5.2 per battery per year*
Benefits of dynamic pricing and DOEs	*$14.2 million*	*$15.1 per battery per year*

Source: HoustonKemp analysis.

Impact of dynamic limits

Keeping the pricing regime constant, the change from a static network limit to a DOE allows VPPs to increase the amount of energy they can discharge when the network is unconstrained,[26] which is the driver of benefits associated with DOEs.

Figure 4.5 illustrates the charging and discharging pattern of a battery under static network limits and DOEs over a single day (1 January 2030). Under both dynamic and static export limits, a battery will aim to:

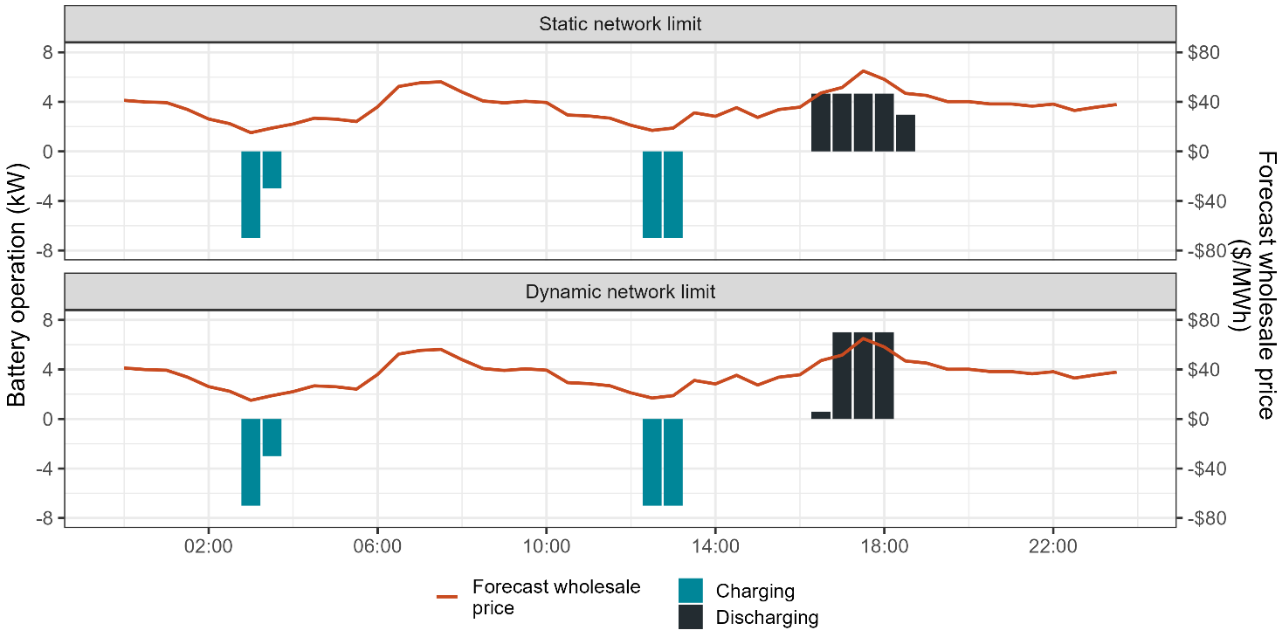
- discharge to the grid around 6pm, when wholesale electricity prices are highest on this day;
- minimise the costs incurred when charging in order to earn wholesale market revenue from discharging later in the day, which occurs during two relative price drops around 3am and 1pm.

The difference between VPP operation under a static export limit and a dynamic network limit on this day is the volume of grid injection that occurs during the highest price periods.

Under dynamic network limits, the battery can discharge to its full power rating in the three half-hour periods with the highest prices. In contrast, the battery cannot discharge at its full power rating during these same periods when receiving a static export limit, requiring the battery to spread its discharge over a number of periods with similar, but lower, wholesale market prices. It follows that the static export limit reduces the revenue obtained when injecting stored electricity back to the grid.

[26] For this analysis, DOEs were assumed to cover dynamic export limits only.

Figure 4.5: Illustration of charging and discharging patterns of a battery under DOEs and static network limits



Note: underlying network prices are ToU tariffs in both cases to isolate the impact of network limits on the charging and discharging behaviour of a battery.

Impact of dynamic pricing

An aggregator has a financial incentive to participate in the wholesale electricity market as it can make a profit by 'buying low' and 'selling high', ie, wholesale market arbitrage. For this to be profitable, the fluctuations in the wholesale electricity price over the course of a day (or couple of days) will need to be greater than the applicable network tariff costs for this operation profile plus any electricity losses from charging and discharging.

In section 3.2, we discuss the price signals created by ToU tariffs and dynamic network tariffs. Table 4.3 below provides a summary of the network tariffs we have assumed with and without DSO investments.

Table 4.3: Comparison of charges and rewards under ToU tariff and dynamic tariff

	ToU tariff	Dynamic tariff
Imports	• $259 per MWh in peak period (3pm to 9pm every day between November to March and June to August) • $40.6 per MWh in off-peak period (all other times)	• $981 per MWh in peak period (5pm to 9pm when highest daily temperature exceeds 26ºC or is below 10ºC) • $0 per MWh in export peak period (10am to 2pm when the lowest daily wholesale price during this period is in the bottom 50% of the year) • $5.0 per MWh at all other times
Exports	• $12.1 per MWh in export peak period (10am to 3pm every day) • -$22.6 per MWh in export reward period (4pm to 9pm every day) • No charges or rewards at all other times	• -$981 per MWh in peak period (5pm to 9pm when highest daily temperature exceeds 26ºC or is below 10ºC) • $18.5 per MWh in export peak period (10am to 2pm when the lowest daily wholesale price during this period is in the bottom 50% of the year) • No charges or rewards at all other times

Source: information provided by Ausgrid.

ToU tariffs provide a price signal that varies across the day, eg, $259 per MWh for imports between 3pm and 9pm and $40.6 per MWh for imports at all other times. This provides a financial incentive for aggregators to avoid charging during peak periods, but in many circumstances this is not required as the network is not congested. Conversely, the ToU tariff for exports provides an incentive to avoid discharging during the middle of the day, when distributed and utility-scale solar generation is at its highest, and an incentive to align discharges with the import peak period.

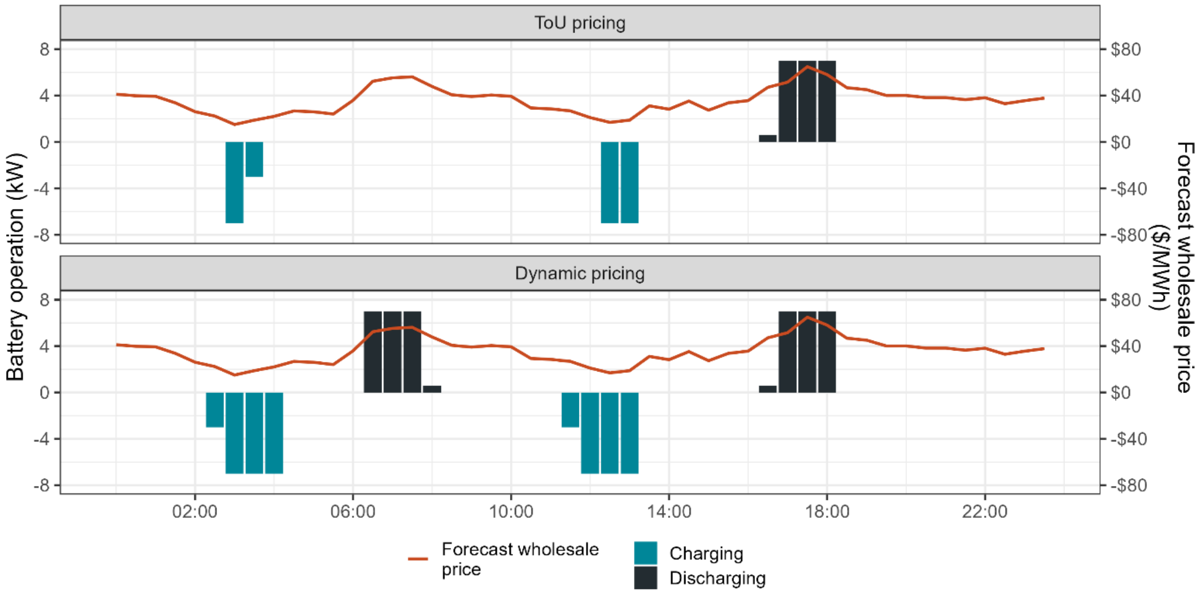
Dynamic network tariffs provide aggregators with the same price signal at all times of the day and days of the year - $5 per MWh for imports and $0 per MWh for exports – unless it is either an import or export peak period. With import and export periods aligning with periods of high and low wholesale market prices respectively, charging and discharging patterns are primarily driven by wholesale market prices under dynamic network tariffs.

Figure 4.6 illustrates how a move from ToU tariffs to dynamic network tariffs affects the charging and discharging behaviour of a VPP for the same day as set out in figure 4.5.

Under a ToU tariff, the VPP has one cycle of charging and discharging during the day. In contrast, under a dynamic network tariff, the VPP has an additional cycle of charging and discharging. The VPP charges at roughly the same time under the two tariffs. However, with a dynamic tariff, relatively more charging occurs at these two times in order to add another discharge in between the two charges while still maintaining the same level of discharge later in the day, as seen with the ToU tariff.

This is due to the lowering of off-peak network prices for imports from $40.6 per MWh under a ToU tariff to $5 per MWh under a dynamic network tariff. In this case, the lower network price, in the magnitude of $35 per MWh, creates additional opportunities for an aggregator to profitably discharge to the wholesale electricity market, given the significantly lower charging costs it will incur to store this electricity.

Figure 4.6: Illustration of charging and discharging patterns of a battery under ToU and dynamic pricing



Note: underlying network limits are dynamic network limits in both cases to isolate the impact of network tariff on the charging and discharging behaviour of a battery.

4.4 Estimating wholesale electricity benefits of DSO investments to EVs

Similar to the case study of VPPs, wholesale electricity market benefits of DSO investments resulting from EVs that are capable of discharging to the network are estimated by applying our battery model as described in section 4.2.2.

4.4.1 Key assumptions

We apply the following assumptions specific to the EV case study in our analysis.

Characteristics of an EV

We leverage our battery modelling to draw insights into the change in an EV's charging and discharging behaviour following DSO investments. To the extent that EVs also have a role in energy storage, the impact of DOEs and dynamic pricing on the participation of EVs in wholesale electricity market participation is similar to those for VPPs.

We assume that an EV's battery has the following technical specifications:

- connects to the network through a 7.4 kW inverter;
- storage capacity of 50 kWh; and
- round-trip efficiency of 85.5 per cent.

Storage capacity is subject to degradation, with effective capacity decreasing gradually from 100 per cent in the 2029-30 financial year to approximately 70 per cent in the 2043-44 financial year.

A distinction between EVs and VPPs is that EVs also used stored electricity for transport, which means that:

- when an EV is travelling on a road, it is not available to participate in the wholesale electricity market; and
- an EV also consumes electricity from the grid to meet the energy required for the transport task.

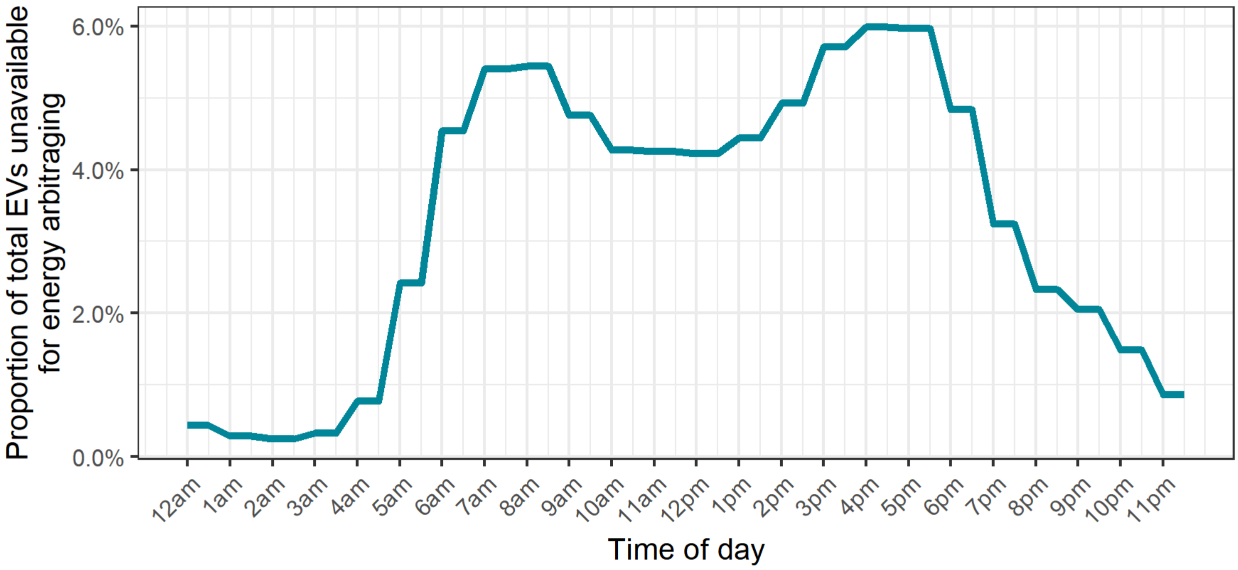
To account for these distinct characteristics of EVs, we make additional assumptions in our EV modelling, including:

- an unavailability profile, which is a half-hourly profile that provides insights into the proportion of the fleet of EVs within Ausgrid's network that are not available to trade in the wholesale electricity market; and
- a distance profile, which is a half-hourly profile that provides insights into the average distance travelled by a passenger vehicle in NSW after accounting for congestion in the network.

Figure 4.7 presents the unavailability profile that is incorporated into the battery modelling for EVs. The unavailability profile captures the proportion of the whole EV fleet that is not available to trade in the wholesale electricity market due to being driven on roads. The unavailability profile is estimated by dividing the total number of passenger vehicles observed at every half-hour during a day across traffic collection stations in NSW[27] by the total number of registered passenger vehicles in NSW.[28]

Our analysis of the unavailability profile suggests that in most cases EVs will be connected to the grid, but this varies significantly across the day. The main period in which EVs are unavailable is between 6am to 6pm, with unavailability of EVs ranging from between 3 to 6 per cent. We assume that this unavailability profile is unchanged over the modelling horizon.

Figure 4.7: Assumed unavailability of electric vehicles for participation in the wholesale electricity market



Source: HoustonKemp analysis of Roads and Maritime Services (NSW government) data.

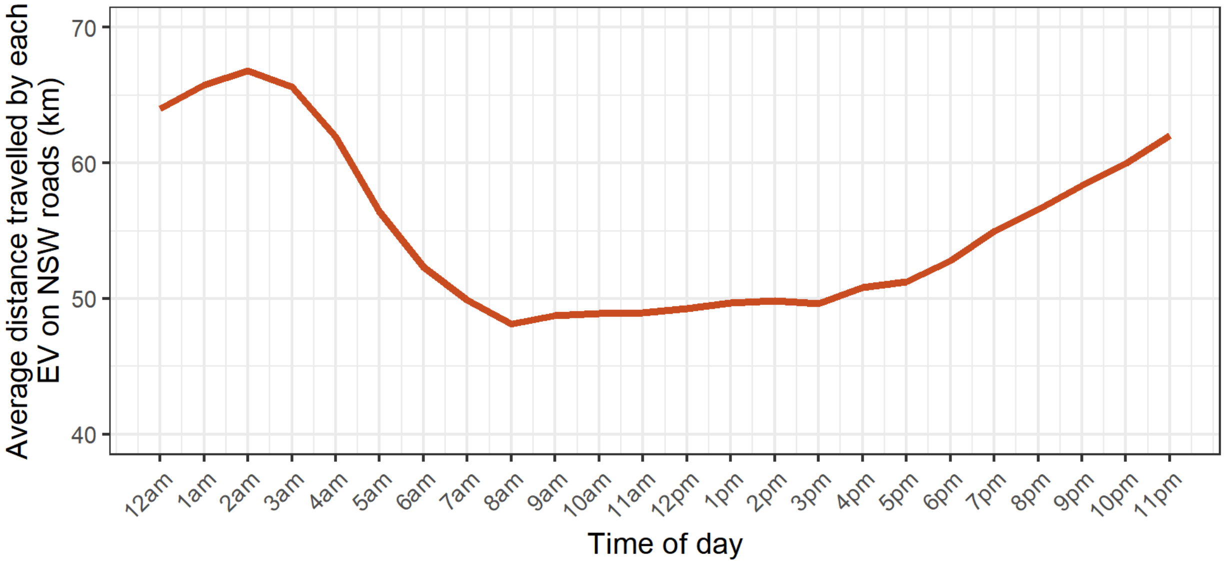
To capture the rate at which an EV's battery draws down electricity to support its use in transport, we assume that an EV will consume 0.15 kWh of electricity for every kilometre travelled. The speed, and therefore distance, that an EV can travel will vary across a day due to traffic congestion. Therefore, we calibrate a distance profile that provides reference to the average distance travelled by each passenger vehicle in NSW by time of day.[29] The distance profile used in our modelling is presented in figure 4.8.

[27] The data are published in the NSW roads traffic volume counts dataset. We use the data in 2016 as this gives us the maximal amount of data available from traffic collection stations. To the extent that these represent a sample of passenger vehicles observed on NSW roads, we apply a scale factor to ensure the total kilometres travelled in NSW in the model (obtained by multiplying the number of vehicles, as implied by the unavailable profile, with the average distance travelled by each vehicle, as implied by the distance profile) is consistent with the Australian Bureau of Statistics' estimate of 48,594 million kilometres travelled intrastate by passenger vehicles in NSW in 2016. See: Transport for NSW, *NSW Roads Traffic Volume Counts API*, available at https://opendata.transport.nsw.gov.au/dataset/nsw-roads-traffic-volume-counts-api, accessed 7 November 2023; and Australian Bureau of Statistics, *9208.0 - Survey of Motor Vehicle Use, Australia, 12 months ended 30 June 2016*, Table 7 Total kilometres travelled, by state/territory of registration by type of vehicle by area of operation.

[28] Australian Bureau of Statistics, *93090DO001_2021 Motor Vehicle Census, Australia, 2021,* Table 1 motor vehicles on register, Type of vehicle–by State/Territory: Census years.

[29] The distance profile is calibrated using average hourly speed data provided by HERE Technologies. The data cover travel speeds of vehicles across the NSW roads network for every hour.

Figure 4.8: Assumed average distance travelled by each electric vehicle by time of day



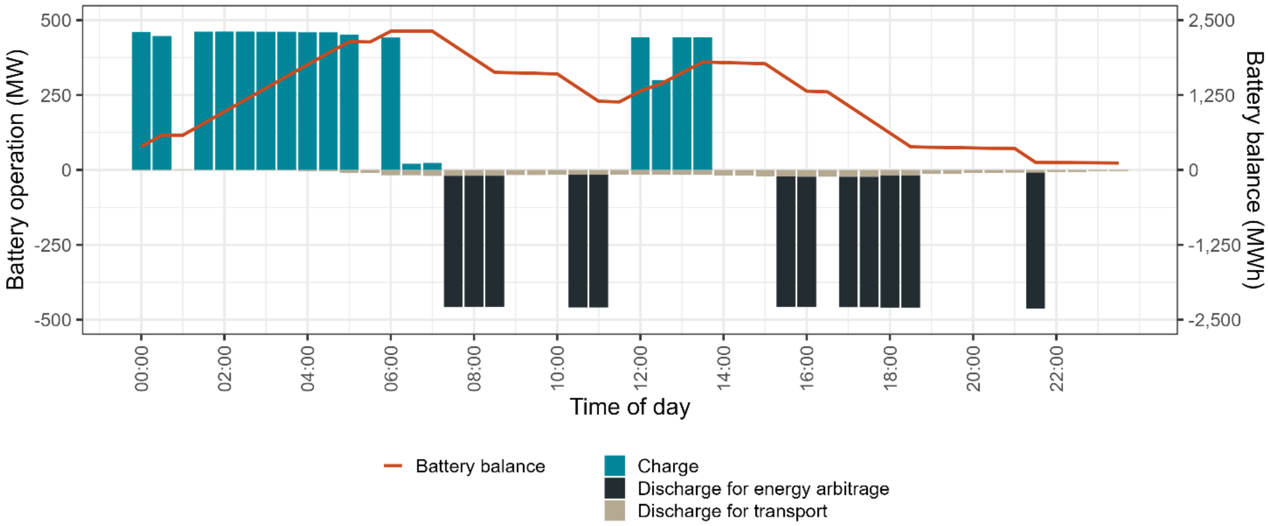
Source: HoustonKemp analysis of observed speed data provided by HERE Technologies.

Our EV battery model accounts for the circumstance where an EV may not travel for a complete hour when it is used on NSW roads. We calibrate the proportion of an hour travelled by each EV by reference to the published information about the total kilometre-vehicles travelled in NSW.

To capture the charging and discharging behaviour of an EV, we assume an EV will maximise wholesale electricity market revenue earned when participating in the wholesale market, subject to its availability and the energy requirements of the transport task. Figure 4.9 below provides an illustrative example of the charging and discharging pattern of a whole fleet of EVs for a one-day period. We observe that:

- EVs charge during low-priced periods at night and during the middle of the day; and
- only a very small proportion of the discharge is related to energy use for transport, ie, most of the energy stored by the EV battery can be used to participate in the wholesale electricity market.

Figure 4.9: Illustrative example of charging and discharging behaviour of EVs



Source: HoustonKemp analysis using HERE Technologies data, Roads and Maritime Services (NSW government) data and information provided by Ausgrid.

Forecast number of EVs connected to Ausgrid's network

We have forecast the number of EVs connected to Ausgrid's network using:

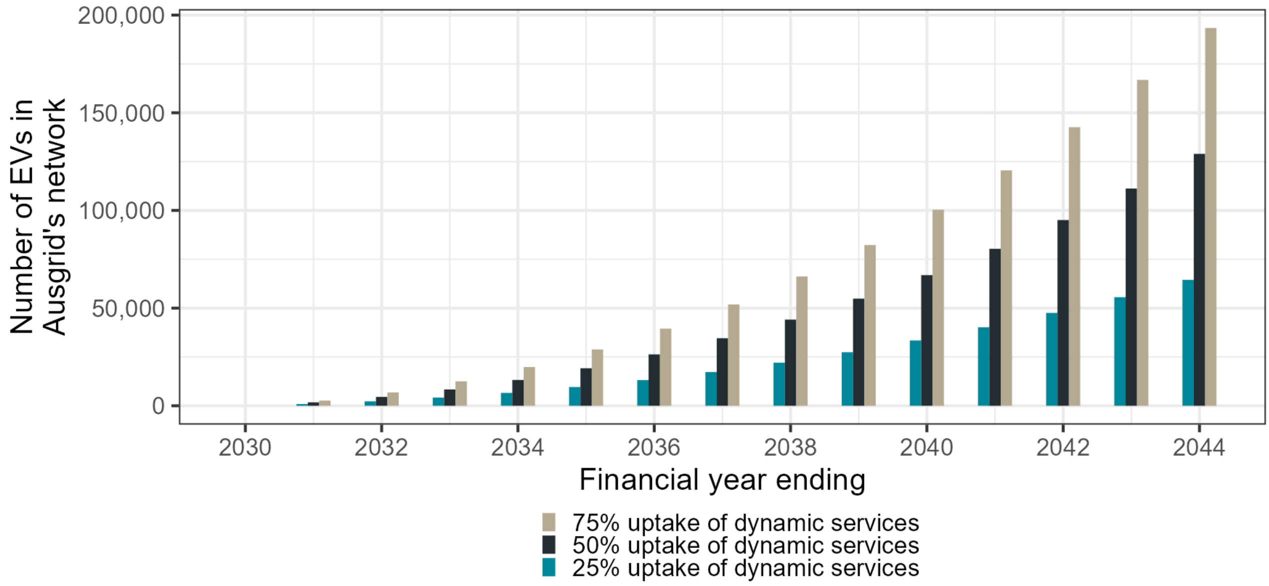
- AEMO's forecast on the proportion of EVs that would have vehicle-to-grid (V2G) capabilities;[30] and
- Ausgrid's forecast of residential EVs connected to its network.

Similar to the case of VPPs, we assume a central adoption rate of DOEs and dynamic network prices of 50 per cent, noting that only EVs that take up dynamic services will benefit from DSO investments. As with our VPP analysis, our previous analysis indicated that total benefits were linear to the take-up rate, as the per unit benefits were constant across all uptake rates.

Figure 4.10 presents the forecast number of EVs in Ausgrid's network that would benefit from DSO investments over the modelling horizon. Similar to the case of VPPs, the forecast number of EVs in Ausgrid's network is assumed to be the same in the 'without' and 'with' DSO investments scenarios. In other words, we have assumed that DSO investments do not increase the number of EVs connected to Ausgrid's network. Therefore, the benefits of DSO investments are a consequence of changes in the charging and discharging behaviour of EVs, rather than by increasing the number of EVs in the network.

[30] AEMO, *2023 IASR assumptions workbook*, 5 September 2023, 'Aggregated energy storages' sheet.

Figure 4.10: Forecast number of electric vehicles with vehicle to grid capabilities in Ausgrid's network, by uptake proportions, FY2023 to FY2044



Source: Ausgrid forecast of residential EVs in its network, adjusted by the share of V2G EVs obtained from AEMO's 2023 inputs, assumptions and scenarios workbook.

4.4.2 Wholesale electricity benefits results for EVs

Starting from the base case where EVs within Ausgrid's network are subject to stepped implementation of static network limits (as set out in section 3.1) and ToU prices, wholesale electricity benefits of DSO investments for all EVs in Ausgrid's network between the 2029-30 and 2043-44 financial years are estimated to be:

- $31.7 million (real $2024, present value) following the implementation of dynamic pricing only;
- $9.2 million (real $2024, present value) following the implementation of DOEs only; and
- $42.2 million (real $2024, present value) following the implementation of both DOEs and dynamic pricing.

On a per-EV and per-year basis, these wholesale electricity benefits are equivalent to:

- $87.4 per EV per year (real $2024, present value) following the implementation of dynamic pricing only;
- $19.3 per EV per year (real $2024, present value) following the implementation of DOEs only; and
- $110.6 per EV per year (real $2024, present value) following the implementation of both DOEs and dynamic pricing.

A summary of the estimated total benefits corresponding to each level of adoption of dynamic services are set out in table 4.2. Estimated annual benefits for each EV are also set out in the last column of the table.

Table 4.4: Estimated wholesale electricity benefits of DSO investments for EVs by DSO capability, real $2024

	Total wholesale electricity market benefits (real $2024, present value)	
DSO capability	**Total (FY2030 to FY2044)**	**Per device per year**
Benefits of dynamic pricing only	*$31.7 million*	*$87.4 per EV per year*
Benefits of DOEs only	*$9.2 million*	*$19.3 per EV per year*
Benefits of dynamic pricing and DOEs	*$42.2 million*	*$110.6 per EV per year*

Source: HoustonKemp analysis.

5. Additional benefits associated with DSO investments

Our analysis has focused on understanding and quantifying wholesale energy benefits associated with the introduction of DOEs and dynamic pricing for VPPs and EVs. However, there are other benefits that we would expect to result from DSO investments. In this section, we briefly set out these additional benefits, which have not been quantified in our analysis.

5.1 Frequency control ancillary service benefits

In addition to participating in the wholesale energy market, batteries are well-positioned to provide frequency control ancillary services (FCAS) due to their capability to quickly dispatch when called upon by AEMO.

Contingency FCAS services are required to restore the frequency of the network back to within the normal operating frequency band (NOFB). Frequency of the network deviates from the NOFB when there is an imbalance in the supply and demand of electricity in the network. This can arise when there is a trip in transmission lines or drop in demand from a large industrial user. Participants in the contingency FCAS market are required to reduce or increase their generation/load to stabilise frequency in the network.

Batteries, in general, are playing an increasingly important role in the provision of FCAS in the NEM. In the absence of DSO investments with the potential introduction of static network limits, we understand batteries may not choose to participate in the FCAS market as there is a likelihood that they might be constrained from operating when they are required to provide FCAS, which would result in financial penalties.

With DSO investments, batteries are provided with greater certainty that there would be no network limits when the network is not constrained. Such certainty increases the likelihood of batteries participating in the FCAS markets. The increase in the participation of batteries in FCAS markets is expected to displace more expensive FCAS providers. This would result in lower costs of providing FCAS overall, which drives FCAS benefits of DSO investments.

5.2 Network benefits

DSO investments can also deliver network benefits by facilitating changes in the use of the network that can avoid the need for other network investments to deliver the same level of network services. In general, network benefits are ascribed to the distribution network providers and subsequently the users of the given network through lower network tariffs.

Network benefits have not been the focus of our analysis. However, we note that there are network benefits of DSO investments. In the case of DSO investments, network benefits arise from the avoided network investments that would have otherwise been made to increase the hosting capacity of the network to accommodate increasing connection of VPPs and EVs to the network.

Without DSO investments, there will likely be a need to introduce static network limits to accommodate the ‘critical peak’ periods that may occur a few times a year. This means that when more batteries are connected to the network, additional network investments are required to increase the hosting capacity of the network to accommodate the higher demand during ‘critical peak’ periods, despite significant under-utilisation of the network during non-peak periods.

By way of contrast, with DSO investments, the capability to have visibility of real-time network conditions allows the DNSP to finely manage congested periods and areas, should they arise, by sending out signals in the form of dynamic limits and tariffs. This will help ‘spread’ network usage over uncongested times, ie, increase network utilisation, and reduce the need to increase the hosting capacity of the network without compromising the demand for using the network.

5.3 Benefits for other technologies

In our analysis, we have focused on the benefits that could arise to VPPs and EVs. However, we understand there are other technologies that could benefit from DSO investments. One example is medium-scale battery energy storage systems (BESS).

A battery energy storage system (BESS) is a type of energy storage system that uses batteries to store and distribute electricity. BESS may seek to connect to Renewable Energy Zones, eg, near a renewable generator, or to a distribution network. A distribution-connected BESS could be classified as ‘medium-scale’, ranging from 10 to 100 MW in size.

We understand that without DSO investments, fixed tariffs would be charged for network usage of these distribution-connected BESSs, with these batteries connected to uncongested areas of the network. However, network congestion could arise as more medium-scale BESSs are connected to the network. This would in turn lead to a need to restrict the operation of BESS or incur network augmentation expenditure.

Having dynamic limits and tariffs can provide battery proponents with an incentive to locate BESS in a more optimal location, which may involve:

- locating in an unconstrained part of the network to avoid the risk of being constrained when accessing other markets and revenue streams; or
- locating in a constrained part of the network to receive significant rewards through a dynamic tariff for providing network support in this area.

5.4 Benefits of other capabilities enabled by DSO investments

In this study, we have focused on the capabilities gained from DOEs and dynamic network prices. Ausgrid will gain other capabilities from DSO investment, such as:

- improved demand modelling and forecasting capabilities;
- improved connection process for CERs; and
- increased visibility of CERs connected within Ausgrid’s network

These capabilities will provide additional economic benefits. For example, improved demand modelling and visibility of CERs connected could help Ausgrid with its network planning, facilitating better use of existing network hosting capability.

5.5 Refinements to the approach used in our study

5.5.1 Wholesale market modelling

We have modelled the benefits of introducing dynamic limits and prices to an individual CER device and then scaled this up based on the number of CERs expected to benefit from DSO investments in Ausgrid’s network. In doing so, we have several implicit, but key, assumptions. For example, we have assumed that wholesale market prices are not influenced by the operation of VPPs and EVs. Further, we have assumed that the behaviour of all VPPs and EVs are identical across the network and do not change as the penetration of CERs increase.

However, it is likely that the wholesale electricity prices will change as a result of VPP and EV participation in the market, and that the behaviour of CERs could differ depending on the particular circumstance or aggregator. In our opinion, modelling these dynamics would require wholesale market modelling, which we have not undertaken as part of this study.

5.5.2 Outcomes of related trials

There are several trials that are currently being undertaken by distribution network businesses that are looking at the benefits of introducing dynamic network limits and prices. One example is Ausgrid's Project Edith. The results from these trials are expected to be available in the coming years. The timing of this study means that we were unable to use the findings of these trials to inform the economic analysis undertaken as part of this project.

A1. Appendix – Additional scenarios considered

In addition to the central scenario presented in the main body of the report, we also run a range of additional scenarios to quantify the sensitivity of our analysis to changes in key underlying assumptions. Table A.1 provides a more detailed description of these additional modelling scenarios. Apart from the assumptions listed below, each scenario maintains all the other assumptions as the central scenario.

Table A.1: Description of key modelling assumptions changed in alternate modelling scenarios

Scenario	Key sensitivity analysed	Value used in modelling	Source
Lower export limits (3 kW and 1.5 kW)	The impact of lower static and dynamic export limits on the benefits of DSO investment	3 and 1.5 kW static and dynamic export limits (two distinct scenarios)	Ausgrid
Central scenario with avoided emissions benefit	Incremental benefits associated with a $ per MWh uplift in benefits associated with the avoided emissions costs from VPP and EV operation	Emissions intensity: from 0.3 tonnes per MWh in the 2029-30 financial year to 0.08 tonnes per MWh in the 2043-44 financial year Cost of carbon emissions: $30 per tonne	Emissions intensity: Green Building Council of Australia, *A practical guide to Electrification | For existing buildings*, March 2022, p 6 Cost of carbon emissions: Ausgrid
Central scenario with VPP discharging limited to periods where wholesale prices exceed $300/MWh	VPP and EV discharging only occurs when the wholesale market price exceeds $300 per MWh for the static ToU tariff case	Export price threshold: $300 per MWh	Ausgrid

We discuss each additional scenario in turn below.

A1.1 Scenarios with a lower export limit

Ausgrid's network is likely to be constrained at times of high solar radiance if no further network investments are made, with the consequence of these constrained periods increasing as installed rooftop PV capacity continues to grow. Moreover, as the number of rooftop PV systems continues to grow, the degree to which an individual customer can export to the grid before these constraints are reached will reduce.

However, uncertainty regarding uptake rates across a range of CERs, including the size and location of these assets, makes it difficult for Ausgrid to predict the nature of network in the future, both with and without DSO investment. As such, Ausgrid has not confirmed the magnitude of any static or dynamic export limits that may be implemented in the future.

In light of this uncertainty, Ausgrid has proposed three potential export limits that reflect the likely range of export limits that may be implemented in the near future, ie:

- a 5 kW export limit, which aligns with the magnitude of the static export limit when SAPN first implemented this limit in December 2017;[31]
- a 3 kW export limit, which is consistent with Ausgrid's calculation of the intrinsic hosting capacity and basic export level for the 2024-29 regulatory control period;[32] and
- a 1.5 kW export limit, which is likely a more realistic estimate for the level of exports per customer supported by the network in the future. This aligns, in magnitude with:
  - SAPN's current export limit offering of 1.5 kW;[33]
  - Essential Energy's proposed basic export level for the 2024-29 regulatory control period of 1.5 kW;[34] and
  - Endeavour Energy's proposed basic export level for the 2024-29 regulatory control period, which is slightly higher at 2 kW.[35]

Ausgrid has assumed a 5 kW export limit in the central scenario, ie, the highest and least restrictive export limit in the range, to remain conservative in this analysis. As this export limit is the least restrictive, the avoided economic costs of removing this static export limit for a dynamic export limit is the lowest of the proposed options.

However, to capture the impact of this uncertainty we have considered two additional scenarios for a lower static export limit than the 5 kW limit assumed in our central scenario, ie, a scenario with a 3 kW export limit and another scenario with a 1.5 kW export limit. We note that in these scenarios, the applicable dynamic export limit will also be 3 or 1.5 kW as appropriate.

These additional scenarios are required to understand how the wholesale market benefits of DSO will increase if lower export limits are required due to further acceleration of CER uptake in the future.

A1.2 Central scenario with quantified emissions reduction benefits

Following the assent of the *Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023*, the National Energy Objectives, as stated in the National Electricity Law, now include an emissions reduction component. Harmonisation of the National Electricity Rules with the updated National Energy Objectives is currently being undertaken by the Australian Energy Market Commission (AEMC).[36]

In anticipation of these changes to the National Electricity Rules and, potentially, a requirement for DNSPs to quantify emissions reduction benefits in future analysis, we have modelled a scenario that explicitly quantifies the avoided emissions costs associated with the change in VPP and EV operation due to dynamic pricing and DOEs.

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[31] SA Power Networks, *Clarification regarding small embedded generation requirements*, available at https://www.sapowernetworks.com.au/data/9972/clarification-regarding-small-embedded-generation-requirements/, accessed 7 November 2023.

[32] We note that Ausgrid proposed a basic export level expressed in kWh per year for the 2024-29 regulatory control period. However, we understand that this volumetric based basic export level is consistent with a basic export level of 3 kW. See: Ausgrid, *Our Pricing Directions Paper for 2024-29*, September 2022, p 19; and Ausgrid, *Our TSS Explanatory Statement for 2024-29*, January 2023, p 16.

[33] SA Power Networks, *Flexible Exports for Solar PV – Lessons Learnt Report 4*, 23 June 2022, p 4.

[34] Essential Energy, *Essential Energy Draft 2024–29 Tariff Structure Statement*, January 2023, p 18.

[35] Endeavour Energy, *Draft Tariff Structure Statement 2024-29 Regulatory Control Period*, 31 January 2023, p 14.

[36] AEMC, Harmonising the national energy rules with the updated national energy objectives (electricity), available at https://www.aemc.gov.au/rule-changes/harmonising-national-energy-rules-updated-national-energy-objectives-electricity, accessed 7 November 2023.

To quantify the avoided emissions benefits, we assume:

- a decreasing annual emissions intensity value for electricity generation each year;[37]
- a cost of emissions of $30 per tonne, in lieu of an official estimate from the AER or AEMC at the time the analysis was undertaken;[38] and
- that all VPP and EV charging occurs from renewable sources and so emissions benefits are obtained only from changes in the discharge profile of VPPs and EVs.[39]

A1.3 Central scenario with VPP discharging limited to high wholesale market price periods only

This scenario is included to account for the risks faced by VPP and EV operators with regard to future price uncertainty, which are amplified when the import charge and export reward of the network tariff are not symmetric.

Our battery model, as with many models of the wholesale electricity market, assumes 'perfect foresight' for the battery operator when performing wholesale market arbitrage. In reality, operators will not know the profile of short-run future price variation and so may charge and discharge less frequently than our model simulates.

When discharging to the grid, a VPP or EV operator must have consideration for the future demand of the owner of the device, ie, a household battery operator or an EV owner. If the operator discharges too much of the customer's stored electricity in the battery, then the operator may be required to purchase more electricity in a near-term future period from the wholesale market on behalf of the owner of the device to:

- meet that customer's demand, assuming the VPP operator is that customer's retailer; or
- provide sufficient charge to that customer's EV for transportation use.

When this occurs in the peak period with a static ToU tariff, the network cost associated with recharging or consuming far exceeds the benefit that the operator would have received when discharging slightly earlier in the peak period. As such, VPP and EV operators face a risk of significant future network tariff costs when discharging stored electricity under asymmetric network tariffs.

The presence of perfect foresight makes it difficult for our modelling framework to appropriately capture this future price uncertainty risk. It follows that our modelling framework results in an over-estimate of the frequency with which a VPP or EV would discharge to the grid, as we do not account for this risk faced by VPP and EV operators when faced with asymmetric static ToU tariffs.

Consequently, VPP and EV operators with a static ToU tariff may only be willing to discharge when the wholesale price is sufficient to offset this asymmetry.

To control for this in our modelling, we have modelled an alternate static tariff scenario where VPP and EV operators will only discharge to the grid when the wholesale market price is sufficiently large to offset the risk associated with future price uncertainty. We have assumed that this 'high price' is $300 per MWh, which is frequently used as a threshold for high prices in the NEM.

[37] Green Building Council of Australia, *A practical guide to Electrification | For existing buildings*, March 2022, p 6.

[38] We note that this estimate is lower than the NSW Government's guidelines for including emissions reductions in cost-benefit analysis. See: NSW Government, *Technical note to NSW Government Guide to Cost-Benefit Analysis TPG23-08*, February 2023.

[39] As the cost of emissions and emissions intensity assumptions used in this analysis only vary by year and not by the time of day, the avoided emissions benefits are obtained solely by an increase in the volume of electricity injections back into the grid from VPPs and EVs, which is facilitated by dynamic pricing and DOEs relative to the static pricing and static limit case.

Where the network tariffs contain symmetric charges, ie, the import price is equal to the export reward, as seen in the dynamic tariffs modelled in this analysis, the consequence and risk to the operator will be lower, since the network cost of recharging is the same as the network reward obtained when discharging, effectively offsetting the gains made when discharging. As a result, there is no need to make an adjustment to VPP and EV operational behaviour in our model since the network tariff does not add to any future price uncertainty faced by these operators.

Table A.2 provides a description of the modelling assumptions for this scenario in the static and dynamic pricing cases.

Table A.2: Description of static and dynamic pricing assumptions in discharge export price scenario

Case	Tariff	Discharge price threshold
Static pricing	*Asymmetric ToU tariff*	*Discharge only when wholesale electricity price exceeds $300 per MWh*
Dynamic pricing	*Symmetric dynamic tariff*	*None*

A1.4 Results of additional scenarios modelled

By way of summary, this scenario analysis provides the following insights:

- the lowering of static and dynamic export limits raises the benefits associated with both DOEs and dynamic prices, with a significantly larger impact on the benefits obtained from DOEs;
- the addition of emissions benefits effectively doubles the wholesale market benefits for VPPs and EVs; and
- a restriction on battery operation under a static ToU tariff to permit discharging only when the wholesale price exceeds $300/MWh significantly increases the benefits of dynamic pricing for both VPPs and EVs. The relative increase in benefits is much larger for VPPs as EVs discharge back to the grid at relatively lower volumes than VPPs (due to the need to use stored electricity for transport purposes), which reduces the effect of this discharge price threshold for EVs relative to VPPs.

Table A.3 presents the increase in total wholesale electricity market benefits in these additional scenarios relative to the central scenario. These additional scenarios indicate that there may be significant upside to the results of the central scenario undertaken in this analysis.

Table A.3: Comparison of total wholesale electricity market benefits of additional scenarios relative to the central scenario

	Increase in total wholesale electricity market benefits relative to the central scenario	
Scenario	**Virtual power plants**	**Electric vehicles**
3 kW export limit	*84%*	*61%*
1.5 kW export limit	*229%*	*165%*
Central scenario with avoided emissions benefit	*103%*	*97%*
Central scenario with VPP discharging limited to periods where wholesale prices exceed $300/MWh	*733%*	*569%*

Table A.4 presents the wholesale electricity market benefits of the various scenarios described above for VPPs. We also reproduce the benefits estimated for the central scenario as set out in section 4.3 of the report for the purpose of comparison. Consistent with the main sections in the report, we present total wholesale market benefits and annual benefits per battery per year.

Table A.4: Wholesale electricity market benefits of VPPs, all modelled scenarios ($2024 real, present value)

		Total wholesale electricity market benefits (real $2024, present value)	
Scenario	**DSO capability**	**Total (FY2030 to FY2044)**	**Per device per year**
5 kW export limit (central scenario)	**Dynamic pricing only**	*$11.8 million*	*$13.0 per battery per year*
	DOEs only	*$6.7 million*	*$5.2 per battery per year*
	Dynamic pricing and DOEs	*$14.2 million*	*$15.1 per battery per year*
3 kW export limit	**Dynamic pricing only**	*$11.9 million*	*$13.5 per battery per year*
	DOEs only	*$18.5 million*	*$14.4 per battery per year*
	Dynamic pricing and DOEs	*$26.1 million*	*$24.3 per battery per year*
1.5 kW export limit	**Dynamic pricing only**	*$18.5 million*	*$17.8 per battery per year*
	DOEs only	*$39.0 million*	*$3.0 per battery per year*
	Dynamic pricing and DOEs	*$46.7 million*	*$40.1 per battery per year*
Central scenario with avoided emissions benefit	**Dynamic pricing only**	*$24.3 million*	*$25.9 per battery per year*
	DOEs only	*$7.6 million*	*$6.1 per battery per year*
	Dynamic pricing and DOEs	*$28.8 million*	*$29.8 per battery per year*
Central scenario with VPP discharging limited to periods where wholesale prices exceed $300/MWh	**Dynamic pricing only**	*$115.7 million*	*$99.1 per battery per year*
	DOEs only	*$5.5 million*	*$3.8 per battery per year*
	Dynamic pricing and DOEs	*$118.1 million*	*$101.2 per battery per year*

Table A.5 presents the wholesale electricity market benefits of the various scenarios described above for EVs. We also reproduce the benefits from the central scenario as set out in section 4.4 of the report for the purpose of comparison. Consistent with the main sections in the report, we present total wholesale market benefits and annual benefits per EV per year.

Table A.5: Wholesale electricity market benefits of EVs, all modelled scenarios ($2024 real, present value)

		Total wholesale electricity market benefits (real $2024, present value)	
Scenario	**DSO capability**	**Total (FY2030 to FY2044)**	**Per device per year**
5 kW export limit (central scenario)	**Dynamic pricing only**	*$31.7 million*	*$87.4 per EV per year*
	DOEs only	*$9.2 million*	*$19.3 per EV per year*
	Dynamic pricing and DOEs	*$42.2 million*	*$110.6 per EV per year*
3 kW export limit	**Dynamic pricing only**	*$29.4 million*	*$80.9 per EV per year*
	DOEs only	*$19.6 million*	*$41.8 per EV per year*
	Dynamic pricing and DOEs	*$52.7 million*	*$133.2 per EV per year*
1.5 kW export limit	**Dynamic pricing only**	*$26.5 million*	*$74.9 per EV per year*
	DOEs only	*$29.5 million*	*$62.3 per EV per year*
	Dynamic pricing and DOEs	*$62.6 million*	*$153.7 per EV per year*
Central scenario with avoided emissions benefit	**Dynamic pricing only**	*$37.1 million*	*$107.6 per EV per year*
	DOEs only	*$10.3 million*	*$22.3 per EV per year*
	Dynamic pricing and DOEs	*$49.2 million*	*$135.2 per EV per year*
Central scenario with VPP discharging limited to periods where wholesale prices exceed $300/MWh	**Dynamic pricing only**	*$70.5 million*	*$189.8 per EV per year*
	DOEs only	*$2.7 million*	*$5.4 per EV per year*
	Dynamic pricing and DOEs	*$81.0 million*	*$213.0 per EV per year*

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