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Project EDGE
Cost Benefit Analysis – Final Report
Main Body

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Access Economics

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Acknowledgements

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The Project EDGE CBA Executive Summary and CBA 'as-built' methodology exist as separate documents. This document is intended to provide the detailed CBA findings.

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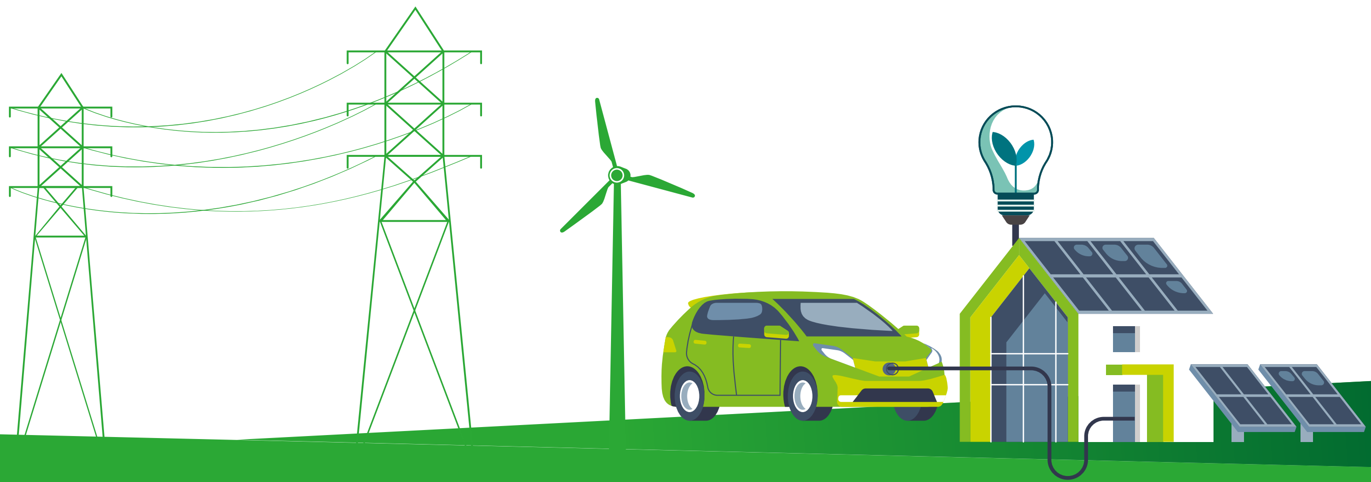
Glossary

Key Terms	Description
Active DER	Refers to DER that actively responds to external signals to apply export and import power limits, and/or dispatch active and reactive power. Active DER can be turned off, ramped up or ramped down.
Bidding	Refers to the activity where DER Aggregators submit information detailing how much energy they would like to offer or consume for each 5-minute dispatch interval, with the capacity/volume offered in 20 different price bands. These bids are submitted to AEMO.
Bi-directional offer	Refers to a wholesale bid which is an offer that can include both amounts of generation and load the DER Aggregator is willing to offer in the market across 20 price bands and in 5-minute dispatch intervals. In Project EDGE a bi-directional offer represents the whole of a DER Aggregator's portfolio collectively identified under a single Dispatchable Unit Identifier (DUID).
Business to business (B2B)	Refers to a generic industry term used to refer to defined business to business interactions between market participants and exclude interactions between a market participant and market systems.
Consumer	Refers to the broader population of electricity customers, regardless of whether they have DER or not.
Controlled load	Refers to the sum of load and/or battery charging activity of the DER Aggregator's DER portfolio. It only includes DER loads under the control of the DER Aggregator. It does not include uncontrolled loads such as household appliances.
Customer	Refers to persons being recruited, or acquired, by a DER Aggregator or retailer, or in the context of a person who forms part of a connection agreement with a DNSP.
Data hub	Refers to digital infrastructure allowing data exchange between parties.
DER Aggregators	Represent DER from many customers, collectively managing devices to provide electricity services as a VPP. DER Aggregators can deliver multiple services on their customers' behalf, including market services to AEMO, local network services to distribution networks and hedging services to Retailers. DER Aggregators are granted permission by customers to use their DER and data to deliver services according to the customers' preferences typically in return for financial payments. DER Aggregators may also be registered energy Retailers (i.e., retailers that operate their own VPPs).
DER capacity	Refers to the capacity in (kW) available to DER for power generation (export) or load (import) at a given point in time. It differs from DER nameplate capacity in that it refers to the capacity available for a particular dispatch interval rather than the DER's full potential capacity.

Key Terms	Description
Distributed Energy Resources Management System (DERMS)	Refers to a software platform used by DNSPs for the coordination and management of DER.
Distribution Network Service Provider (DNSP)	Refers to a DNSP acting in their current role of owning, controlling or operating a distribution system as defined in the NER.
Distribution System Operator (DSO)	Refers to the DSO which in the NER currently refers to an entity registered with AEMO that is responsible for controlling or operating a portion of the distribution system.
Dynamic export limit	Refers to signals sent by retailers to customers' DER or DER Aggregators to incentivise a reduction in the customer exports from a reduction in DER controlled generation or an increase in controlled load, to limit a retailer's negative wholesale price exposure. This is distinct from the flexible export limits that DNSPs send to indicate the technical operating limits of the local distribution network.
Dynamic operating envelope (DOE)	Refers to the limits on the amount of electric power that a customer can import from and export to the distribution grid at a point in time, where these limits (operating envelope) can vary for each dispatch interval according to the prevailing grid conditions (i.e., are dynamic). DOEs represent the technical operating limits of the local distribution network in contrast to static limits that are more conservatively determined and set at the time of connection to the distribution grid.
Feed-in Tariff (FiT)	Refers to a payment for electricity fed into the grid from a renewable energy source.
Flex bidding	Refers to a mode of bidding tested in Project EDGE whereby the definition of power quantity (kW) submitted in the bi-directional offer represents the sum of controllable DER devices (load and/or generation, not individual devices) across the DER Aggregator's registered portfolio of NMIs. It is estimated at a real or virtual common measurement point of controllable devices at each customer site and then aggregated to a portfolio level number. It represents a DER Aggregator's intended gross DER activity excluding uncontrolled load and generation.
Local Services Exchange	Refers to the interface to facilitate visible, scalable and competitive trade of DER-based network support services for local network constraint management.

Key Terms	Description
LSE portfolio	Refers to a subset of a DER Aggregator's DER portfolio used to provide network support services. Since network support services are needed for local network areas, an LSE portfolio comprises one or more NMIs within the same constrained local network area. As such, a DER Aggregator can have multiple LSE portfolios within its overall DER portfolio. These may be organised within a DER Aggregator's own systems and/or registered with a DSO.
Multi Criteria Analysis (MCA)	Refers to an analysis process that scores and rates options against multiple criteria. MCA provides a way of analysing alternatives against outcomes that are important for decision-makers, but which cannot be readily quantified and monetised.
Net NMI bidding	Refers to a mode of bidding tested in Project EDGE whereby the definition of power quantity (kW) submitted in the bi-directional offer represents the sum of net connection point power flows (controlled and uncontrolled load and/or generation, not individual devices) across the DER Aggregator's registered portfolio of NMIs. It is estimated at a real or virtual common measurement point close to the grid connection point at each customer site and then aggregated to a portfolio level number. It represents a DER Aggregator's intended net DER activity including uncontrolled load and generation.
Network support service	Refers to energy services that a DNSP or DSO procures to manage network constraints. Examples include an increase or decrease in demand, or voltage management services.
Original Equipment Manufacturer	Refers to a company that designs and manufactures components or products that are then sold under another company's name.
Passive DER	Refers to DER that is not enabled to respond to external signals. This is forecast as uncontrolled load and/or generation.
Portfolio	Refers to a DER Aggregators' entire fleet of registered DER devices under its control that forms its VPP.
Portfolio telemetry	Refers to the actual measurement of total power flow for all sites and controllable DER registered in a DER Aggregator's portfolio (also referred to as DUID level). In Project EDGE portfolio telemetry files provided Active Power, Controlled Generation, Controlled Load and energy stored (kWh).
Power system security	Refers to: • The technical parameters of the power system such as voltage and frequency. • The rate at which these parameters might change. • The ability of the system to withstand faults. The power system is secure when technical parameters such as voltage and frequency are maintained within defined limits. To maintain frequency the power system must instantaneously balance electricity supply against demand.

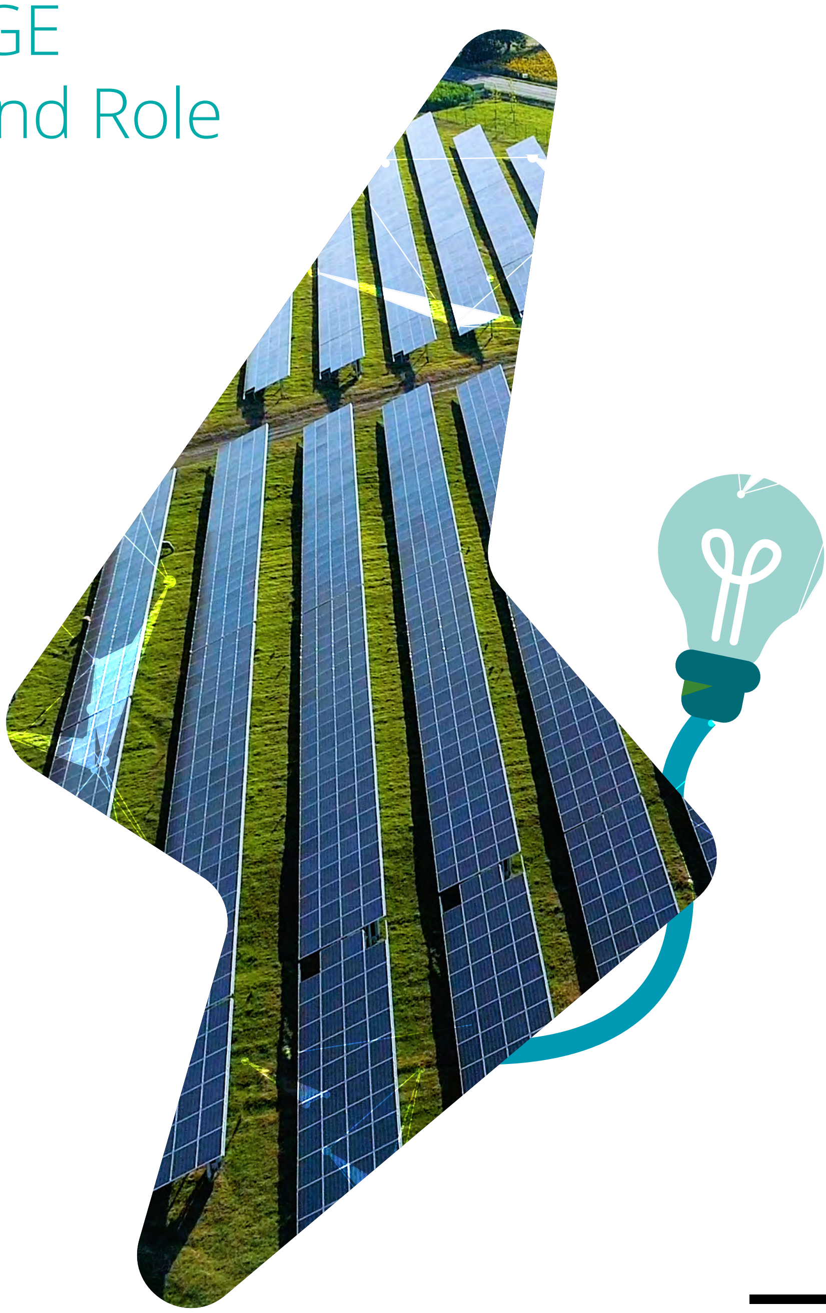
Key Terms	Description
Project Participants	Refers to AEMO, AusNet and Mondo.
Reliability	Refers to when the power system has enough generation, demand response and network capacity to supply consumers with the energy that they demand with a very high degree of confidence. This requires: • Well-functioning electricity spot and contract markets providing clear price signals, along with forecasts and notices from the system operator, AEMO, backed up by policy certainty from governments. This gives market participants incentives and information to supply generation and demand response when and where it is needed. • A reliable transmission and distribution network (the poles and wires). • The system being in a secure operating state, that is, able to withstand shocks to its technical equilibrium.
Social licence	Refers to in the context of Project EDGE the permission provided by consumers to government or institutions to control their DER system, above and beyond that required by law. It refers specifically to customers' support and trust that enables their privately-owned DER to be managed in a way that delivers additional benefits for them, the power system, and all consumers.
Uncontrolled load	Refers to consumers' essential electricity service utilisation. It is generally consumption from everyday electrical appliance and use. It also includes passive DER generation which might offset load.
Vehicle-to-grid (V2G)	Refers to the concept of discharging an EV battery to serve a secondary purpose (other than mobility for that EV). Specifically, this refers to discharge capability that provides wider system services.
Virtual Power Plant (VPP)	Refers to an aggregation of small-scale DER, such as decentralised generation (e.g., rooftop PV), storage, and controllable loads, coordinated to deliver large-scale services for power system and distribution network operations and electricity markets. VPPs are operated by DER Aggregators and are synonymous with DER Aggregator/DER 'fleet' and 'portfolio'.



Acronym	Full Name
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
ARENA	Australian Renewable Energy Agency
BTM	Behind The Meter
B2B	Business-to-business
Capex	Capital Expenditure
CBA	Cost Benefit Analysis
CECV	Customer Export Curtailment Value
CER	Consumer Energy Resource(s)
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
DER	Distributed Energy Resource(s)
DERMS	Distributed Energy Resources Management System
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DSO	Distribution System Operator
DUID	Dispatchable Unit Identifier
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FiT	Feed-in tariff
FTA	Flexible Trading Arrangement
Hp	Hypotheses
IESS	Integrating Energy Storage Systems
ISP	Integrated System Plan
kVA	Kilovolt-amps
kW	Kilowatt

kWh	Kilowatt Hour
LRMC	Long Run Marginal Cost
LSE	Local Services Exchange
LV	Low Voltage
MCA	Multi-criteria Analysis
MW	Megawatt
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Meter Identifier
O&M	Operating and Maintenance
OE	Operating Envelope
OEM	Original Equipment Manufacturer
Opex	Operating Expenditure
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
RQ	Research Question
SCED	Security Constrained Economic Dispatch
SRMC	Short Run Marginal Cost
SME	Subject Matter Experts
TEM	Techno-Economic Modelling
TNSP	Transmission Network Service Provider
UoM	University of Melbourne
V2G	Vehicle-to-grid
VCR	Value of Customer Reliability
VPP	Virtual Power Plant
WDR	Wholesale Demand Response

1
Project EDGE Overview and Role of the CBA



The CBA explores the conditions under which DER integration in the NEM will serve the long-term interests of electricity consumers. The CBA is intended to provide direction to energy market participants and policy makers of the economic value associated with selected capabilities of DER participation.

1.1 Project EDGE

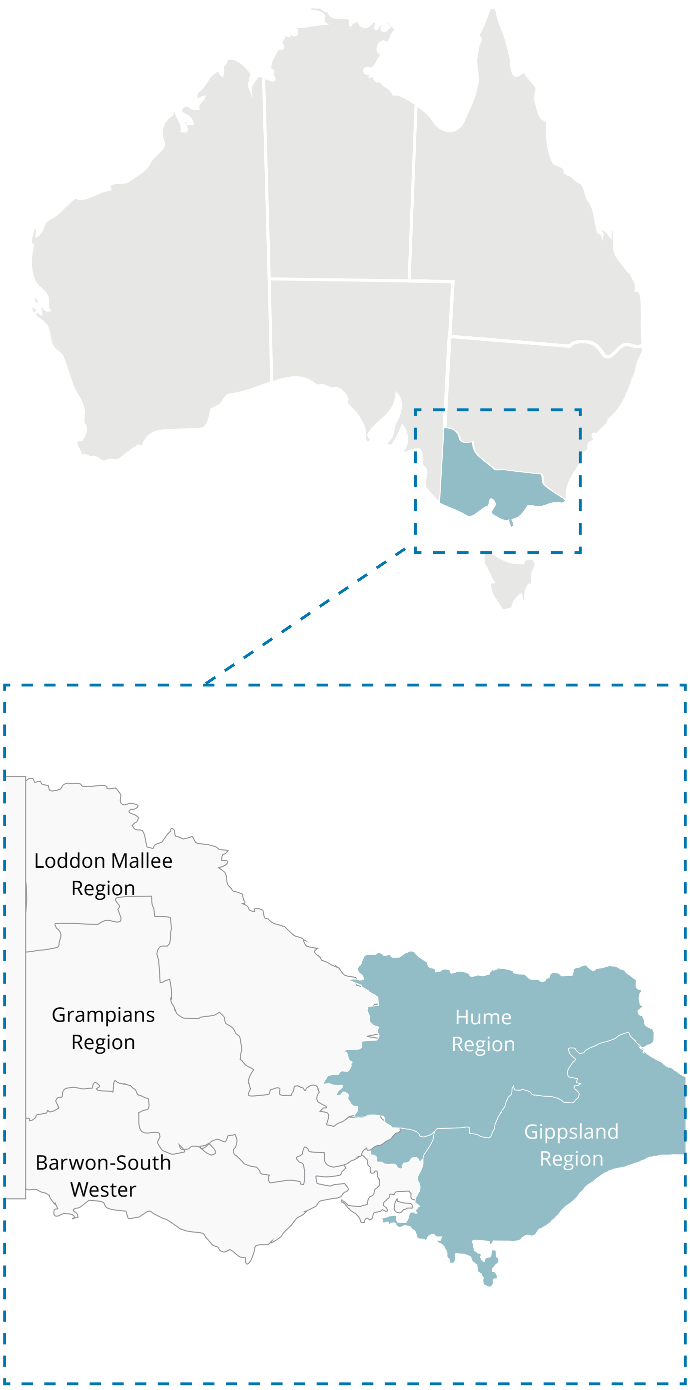
Project EDGE is a multi-year project designed to demonstrate an end-to-end market arrangement for coordinating DER to provide both wholesale and local network services within the constraints of the distribution network.

Project EDGE is a collaboration between AEMO, AusNet and Mondo, with financial support from the Australian Renewable Energy Agency (ARENA) and is focused within the AusNet distribution service area within the Australian state of Victoria.

Project EDGE considered three key capabilities to provide increased integration of DER in the NEM:

- **Wholesale integration of DER:** Coordinating DER fleets such that they are forecast, bid and dispatched as if they are participating in existing wholesale markets (electricity and ancillary services), while considering distribution network limits. DNSPs calculate and communicate DOEs, which represent network limits to market participants with registered DER. DER Aggregators coordinate their fleets by submitting bi-directional offers within the DOEs and act on dispatch instructions from AEMO.
- **Local Services Exchange (LSE):** The interface to facilitate visible, scalable and competitive trade of DER-based network support services for local network constraint management.
- **Scalable DER data exchange:** Enabling secure, efficient, and scalable DER data exchange between AEMO, DNSPs and DER Aggregators to facilitate DER service delivery. Project EDGE tested a data hub[1] approach to scalable DER data exchange.

Figure 1.1 Project EDGE off-market proof-of-concept location



1.2 Why now?

It is exciting to imagine a future where most of our energy needs are met by renewable and low-cost sources of energy.

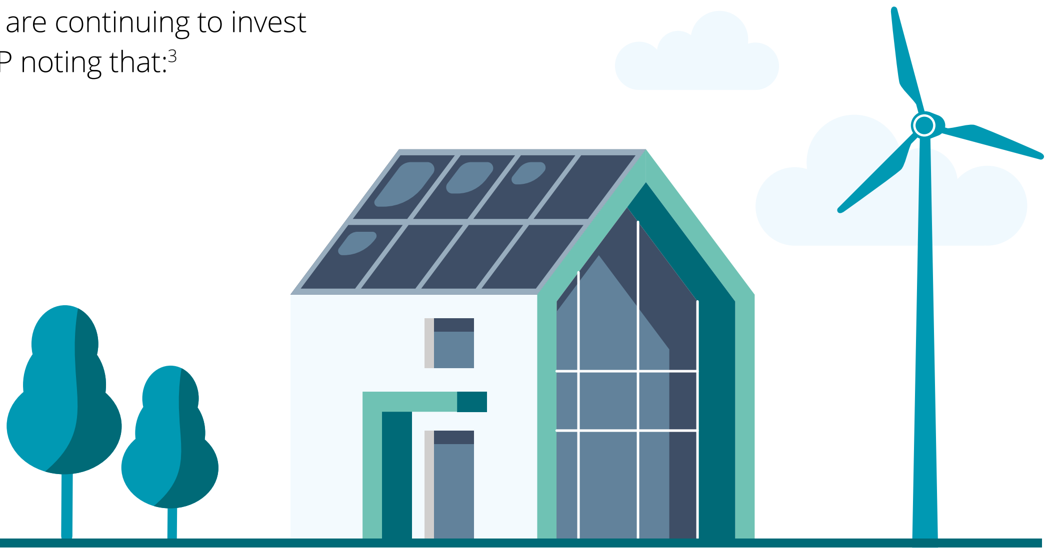
A coordinated approach to the integration of an expanding volume of distributed energy resources (DER)[2] into the electricity market can support this future through mitigating existing barriers to DER uptake and lowering costs for all consumers.

Without action, we instead risk making operation of the electricity market more difficult and more expensive for all consumers. In simple terms, this means that reliability of electricity supply and the costs to access that supply will be adversely impacted unless we urgently agree on a better way to transition to a net zero emissions future.

Right now, Australia's energy landscape is experiencing a rapid transition as coal-fired synchronous generation reaches end-of-life and the shift to renewable generation accelerates. The increased coordination of DER offers the opportunity to further accelerate this transition and potentially unlock operational efficiencies that serve to benefit all consumers.

Households and businesses are continuing to invest in DER, with AEMO's 2022 ISP noting that:[3]

Today, approximately 30% of detached homes in the National Electricity Market (NEM) have rooftop PV, their approximately 15 Gigawatt (GW) of capacity meeting their owners' energy needs and exporting surplus back into the grid. By 2032, over half of the homes in the NEM are likely to do so, rising to 65% with 69 GW of capacity by 2050, with most systems complemented by battery energy storage. Assuming that investment in distribution systems is coordinated with DER expansion for efficient operation and export, their 93 Terawatt hour (TWh) of annual electricity generation would meet nearly one fifth of the NEM's forecast total underlying demand.



[1] Refers to digital infrastructure allowing data exchange between participants. Project EDGE tested a centralised and decentralised data hub infrastructure to facilitate data exchange between participants.

[2] The term Consumer Energy Resources (CER) has emerged to refer to consumer-owned DER and is used interchangeably with DER by some stakeholders. This report uses the term DER to cover all assets connected to the distribution network, both consumer and non-consumer owned or leased.

[3] AEMO, 2022 ISP (June 2022), page 10, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

Taking a coordinated approach to managing the integration of DER into the NEM would help maximise the benefits of DER for all consumers. Without effective integration into the electricity system, DER growth could continue to create challenges for managing the power system, with minimum system load, limited visibility, and unpredictable DER behaviour impacting the ability to maintain reliable and secure electricity supply[4].

The implementation pathway for integrating DER in the NEM should also recognise that the electricity market itself will continue to evolve in response to a broad range of factors including the pace of the transition towards renewables, penetration rates of DER, policy settings and market reforms. Therefore, variations may exist between DNSPs when seeking to establish an implementation pathway.

1.2.1 Role of a two-sided market

The provision of electricity is heading toward a two-sided market as DER Customers choose to generate at least some of their electricity needs themselves. This structure has the potential to provide an efficient and sustainable way to coordinate and integrate DER into the electricity system, allowing consumers to benefit from a future with high levels of DER.

The ESB has recognised the benefits (and challenges) of a two-sided market[5]:

The clearest opportunity from the energy transition is the development of a two-sided market. A two-sided market can deliver benefits of improved efficiency and innovation, and customer benefits including better prices and more choice.

However, the transition also includes challenges for security and reliability as supply and demand becomes more variable and uncertain, and for industry transitions away from generation that traditionally delivered security services (such as inertia and voltage control). Any new market design needs to realise the benefits and mitigate the risks involved in the transition.

The ESB has also acknowledged that DER integration trials will provide valuable insights for the development of the two-sided market design[6].

Alongside Project EDGE, there are several other trials and pilots (such as Project Symphony, Project Edith and Project Converge) that are currently exploring how DER can deliver value.

1.2.2 Roles and responsibilities

Understanding the value of integrating DER into the NEM includes examining the roles of market participants and the responsibilities assigned to those roles.

Project EDGE sought to examine (as per its Research Plan[7]), the roles and responsibilities of market participants within the bounds of the OpEN Hybrid Model[8]. This included the extent to which these roles and responsibilities support the National Electricity Objective (NEO) and align with those under the existing regulatory frameworks. The roles and responsibilities in the Project EDGE arrangement are outlined in the Figure 1.2[9].

[4] ESB, Moving to a Two-Sided Market (April 2020), at https://webarchive.nla.gov.au/awa/20201111041044/http:/www.coagenergycouncil.gov.au/publications/two-sided-markets
[5] Ibid.
[6] Ibid.
[7] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35
[8] AEMO and Energy Networks Australia (2019), at http://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf
[9] Project EDGE, Public Interim Report (July 2022), page 21, at https://aemo.com.au/-/media/files/initiatives/der/2022/public-interim-report.pdf?la=en&hash=45036CAC8BE6B43C186426B0B5B8005C

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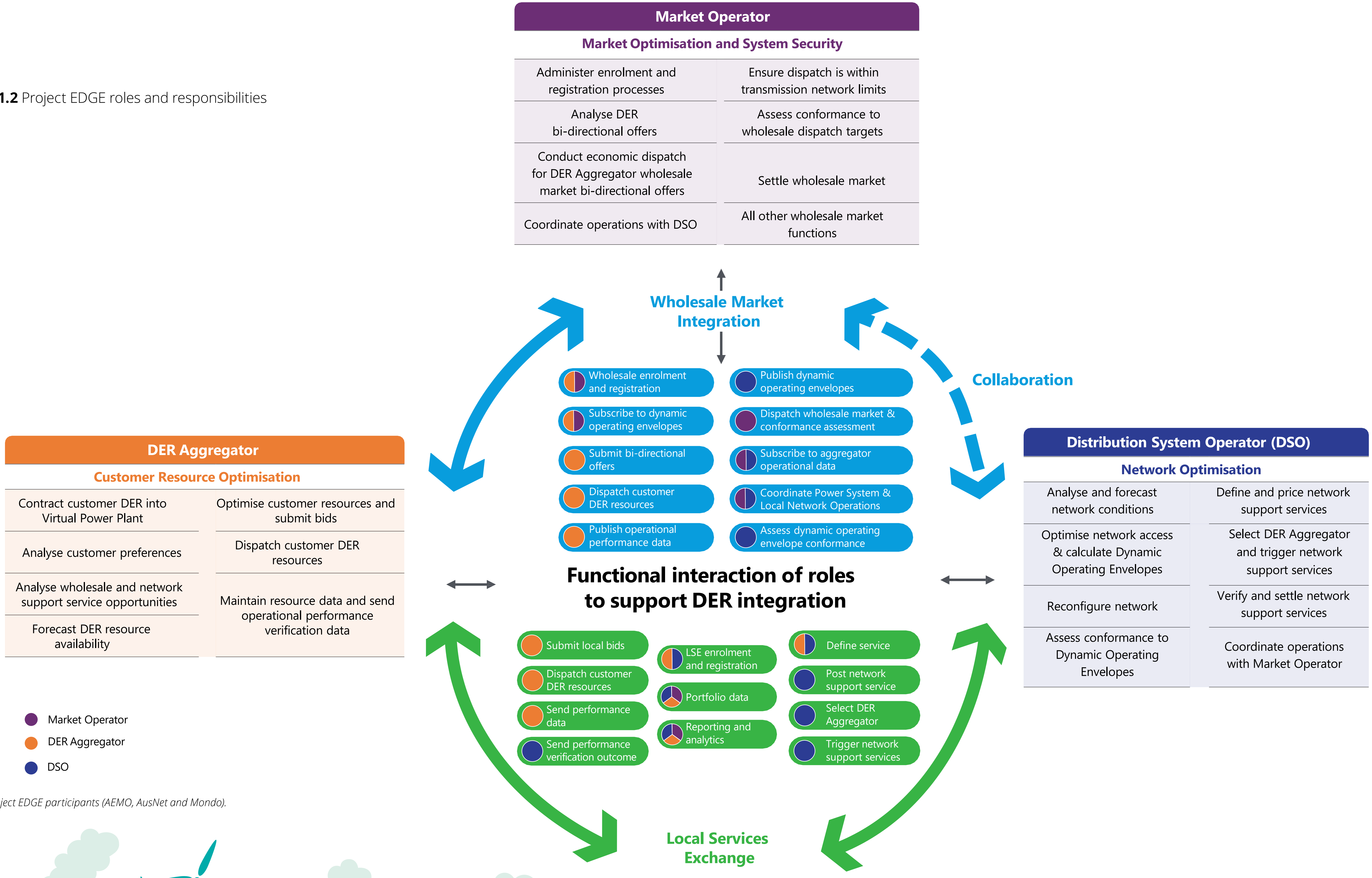
Figure 1.2 Project EDGE roles and responsibilities



Source: Project EDGE participants (AEMO, AusNet and Mondo).

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1.2.3 Barriers to DER Value

Maximising the value of DER requires the removal or reduction of existing barriers and their potential to impact the secure and reliable operation of the NEM[10]. Barriers include:

- **Overly conservative and static export limits** that result in the curtailment of DER (e.g., lost export).
- **Fragmented market frameworks** for coordination of active DER, restricting the ability to provide both wholesale and local network services from the same DER portfolio.
- **Lack of standardisation** in terms of DER data exchange which limits the scalability of DER.
- **Limited visibility** of active DER minimises situational awareness and forward-looking operational and network planning for the Market Operator and DNSPs.
- **Social license** challenges, for example obtaining consumer permission to allow third party control of their active DER.

Project EDGE sought to assess how selected capabilities for DER participation can mitigate these barriers and thereby maximise the value of DER.

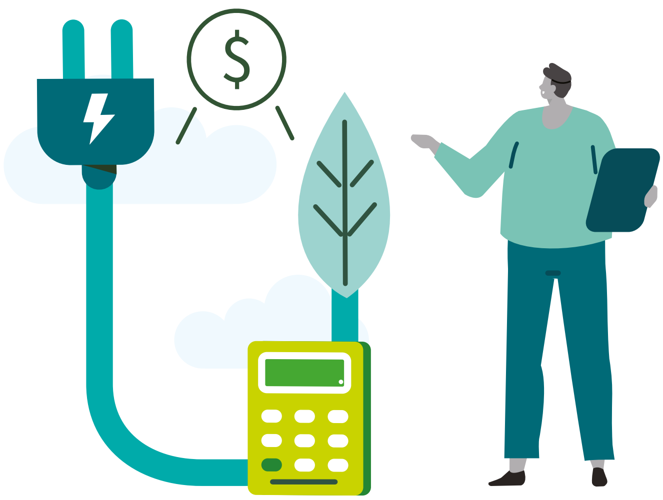
1.3 Role of the CBA within Project EDGE

The purpose of the CBA is to provide policymakers and industry leaders with an independent assessment of the costs and benefits associated with NEM wide implementation of the demonstrated DER integration model using evidence from Project EDGE. The CBA is intended to inform policy decisions and industry choices that provide optimal outcomes for consumers in the transition to net zero emissions and a higher DER electricity market.

The CBA is ultimately an economic assessment. Prepared in consultation with industry stakeholders, the guiding principle of the CBA was the use of market inputs to test the outcomes of the Project EDGE field trial under 'as real' conditions of the NEM at the time of quantification.

The CBA is intended to provide insights and direction to market participants and policy makers of the economic value associated with selected capabilities of DER participation in the NEM. This includes DOEs, scalable DER data exchange and an LSE. It explores a range of scenarios under which DER participation within the NEM would deliver the long-term interests of electricity consumers[11] across a 20-year time horizon (FY23-FY42).

The CBA is not intended to act as a business or investment case for individual market participants. Further, the applicability of its findings is limited to an understanding of the energy market as of March 2023, and through the voluntary contributions of the Project EDGE participants (AEMO, AusNet and Mondo), DER Aggregators participating in Project EDGE, non-participating DER Aggregators and technology vendors.



[10] AEMO (August 2022), at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en

[11] The CBA is not intended to act as a business or investment case for individual market participants.

The CBA has drawn upon multiple Project EDGE streams such as the Research Plan[12], specialised techno-economic modelling (TEM) undertaken by the University of Melbourne (UoM), Project EDGE field trial outcomes and extensive stakeholder engagement.

At a high-level the CBA involved the following steps[13]:

1. Base case definition

- There are two sets of load and DER assumptions, creating two base cases (Scenario 1 and 6):
  - The 2022 Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) Step Change load and DER assumptions[14] (AEMO ISP Step Change), reflected in Scenarios 1-5.
  - A set of high DER load and uptake assumptions[15] (High DER), reflected in Scenarios 6-10.
- The identification of plausible base cases provides the datum from which the impact of changes could be quantified, i.e., the benefits and costs of scenarios were measured as an incremental change from the specified base cases.
- The base cases assume:
  - A simplistic DOE configuration and a point-to-point approach to scalable DER data exchange
  - The implementation of rule changes requiring new DER installations to comply with flexible exports and satisfactory DER customer products to enable active DER to be separately managed from passive load.
  - No implementation of Scheduled Lite[16] type participation arrangements, limiting Market Operator and DNSP visibility of DER (however all other scenarios assume Scheduled Lite to account for the incremental impact).

2. Identification of alternative scenarios and period of analysis

- Scenarios of varying complexity and sophistication compared to the base cases were developed, representing different DOE and market configurations.
- The CBA analysed the impacts of integrating DER based on the Project EDGE arrangement within the NEM over a 20-year time horizon (FY23-FY42).

3. Costs and benefits specification across market participants

- The specification of costs and benefits across market participants, drawn from a combination of modelling and stakeholder engagement.

4. Modelling costs and benefits (incremental to the base cases)

- Modelling was undertaken to estimate the present values of the costs and benefits, where practical, costs and benefits were monetised. If not practical, e.g., due to the lack of suitable data, these were described qualitatively.
- The discounting of future costs and benefits reflects the time value of money and uncertainty of future cash flows.

[12] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

[13] Detailed information on the Project EDGE CBA 'as-built' methodology is published at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

[14] AEMO, 2022 ISP (June 2022), at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

[15] Energeia (2020). Renew DER Optimisation (Stage II): Final report (for Renew), page 4 and page 32, at https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf

[16] AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite

5. Findings, sensitivity testing and report

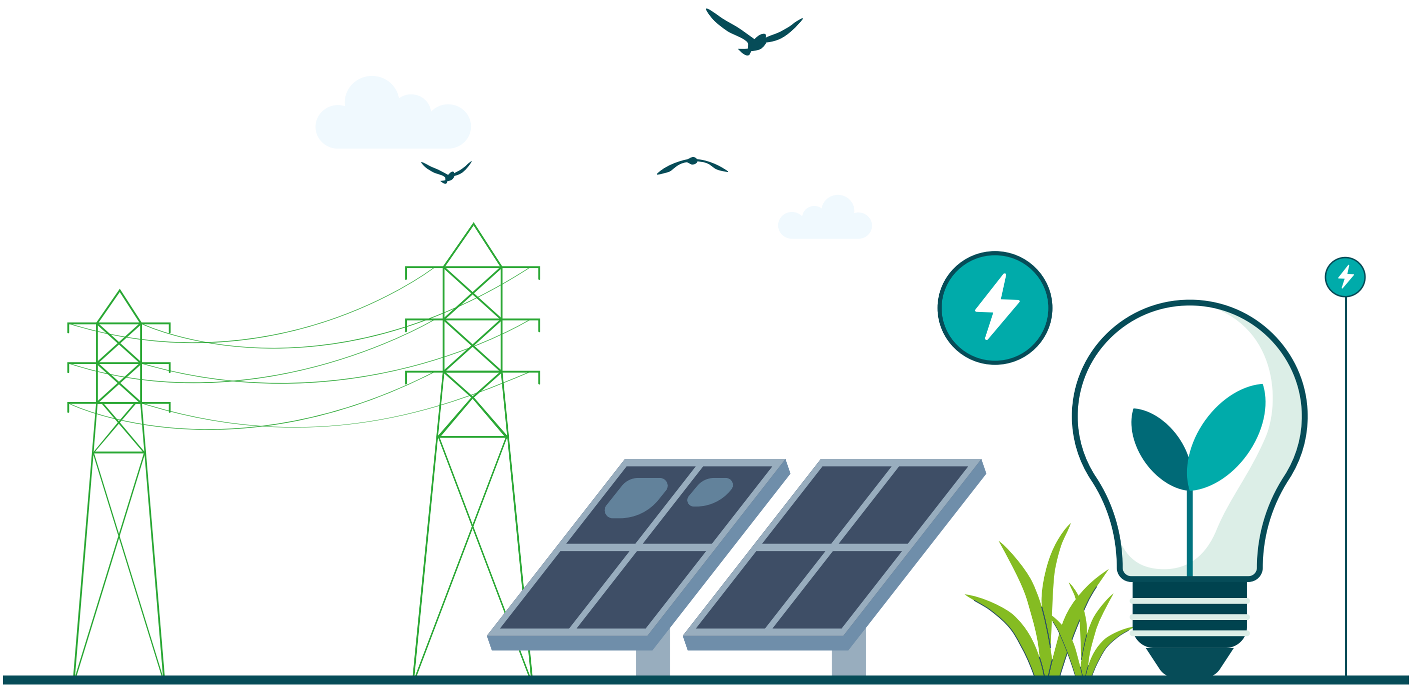
- Findings are expressed in terms of:
  - Whole-of-system outcomes across each scenario (in comparison to the base cases).
  - Across market participants (in comparison to the base cases).
  - Across capabilities identified in Project EDGE (e.g., scalable DER data exchange, LSE and visibility of DER).
  - Relation to each relevant research question[17].
- Sensitivity analysis was undertaken on discount rates and key cost categories (e.g., generation build, operational and maintenance costs and distribution hosting capacity costs).

The CBA is an independent stream under Project EDGE. The full scope of technical findings from Project EDGE is available on the AEMO website[18].

1.4 Outline of the remaining sections

The balance of this report is structured as follows:

- **Section 2** is an overview of the CBA methodology, including the scope, tools utilised and stakeholder engagement.
- **Section 3** outlines CBA findings and sensitivity analysis.
- **Section 4** assesses the roles and responsibilities of key market participants in the Project EDGE arrangement.
- **Section 5** provides market participants and policy makers with directional guidance to support future DER integration in the NEM.
- **Appendix A** maps the CBA findings to the relevant research questions and associated hypotheses from the Research Plan[19].
- **Appendix B** includes additional detail on the CBA findings regarding the defined uplift in visibility of DER.



[17] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35
[18] AEMO, Project EDGE technical findings, at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports
[19] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

2
CBA Methodology

The CBA tested 10 scenarios to measure the costs and benefits of DER integration in the NEM under different DER uptake assumptions, DOE configurations and market configurations (such as scalable DER data exchange and an local services exchange).

2.1 CBA Scenarios and Key Assumptions

2.1.1 CBA scenarios

The CBA considers two scenario sets, the first of which reflects a likely future state (Scenarios 1-5) and the second of which represents a more accelerated rate of DER uptake (Scenarios 6-10). These are designed to measure the costs and benefits of DER integration in the NEM, and were structured to ensure variation across at least one of three areas:

- Load and DER uptake assumptions.
- DOE configurations, which differ by frequency, customer coverage, calculation methodology and objective function.
- Market configurations (such as scalable DER data exchange approaches (e.g., data hub) and LSE).

Load and DER uptake assumptions

The CBA has applied two sets of load and DER assumptions:

1. The AEMO ISP Step Change assumptions[20] reflected in Scenarios 1-5, and
2. The High DER assumptions[21], reflected in Scenarios 6-10.

The AEMO ISP Step Change assumptions involve a consistently fast-paced transition from fossil fuels to renewable energy resources in the NEM.

The High DER assumptions represent a more accelerated level of DER penetration than the AEMO ISP Step Change assumptions, allowing a comparison of DOE and market configurations under a higher rate of DER penetration[22]. The High DER assumptions were developed to represent an economic environment that stimulates greater levels of DER adoption.

While the 2022 ISP also provided a scenario with higher DER adoption than the AEMO ISP Step Change (i.e., Hydrogen Superpower Scenario), the High DER assumptions have greater alignment with tested capabilities and so were ultimately included in the CBA.

This was based on the view that the High DER assumptions better showcase the pathway to a high DER future given the Hydrogen Superpower Scenario was predicated on a substantial shift in energy demand by hydrogen electrolysers and material anticipated policy change, rather than commercial factors relating directly to DER.

[20] AEMO, 2022 ISP (June 2022), at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en

[21] Energeia (2020). Renew DER Optimisation (Stage II): Final report (for Renew), page 4 and page 32, at https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf

[22] The High DER load and DER assumption figures are taken from Energeia's 2021 Renew DER Optimisation (Stage II) final report. The engagement received funding from ECA. Energeia was the technical consultant for this engagement and modelled its own High DER scenario.

Information on the load and DER assumptions in the CBA scenarios are listed in Table 2.1 and 2.2 below.

Table 2.1 Comparison of load and DER assumptions in the CBA scenarios

	Scenarios 1-5	Scenarios 6-10
Solar Uptake	AEMO ISP Step Change Scenario	High DER
Battery Uptake		
Electricity Consumption Growth		AEMO ISP Step Change Scenario
EV Uptake		
VPP Uptake		
Customer Connection Growth		

Table 2.2 Comparison of DER assumptions in the CBA scenarios

		Scenarios 1-5 AEMO ISP Step Change	Scenarios 6-10 High DER
Solar PV	Residential	34% by 2030 40% by 2042	90% by 2030 93% by 2042
	Commercial	32% by 2030 41% by 2042	90% by 2030 93% by 2042
Storage	Residential	12% by 2030 29% by 2042	83% by 2030 93% by 2042
	Commercial	22% by 2030 52% by 2042	84% by 2030 93% by 2042
VPP Participation[23] (% of Storage)		41% by 2030 53% by 2042	41% by 2030 53% by 2042

Notes: Expressed as the percentage of all dwellings with installed DER, excluding VPP participation which is a percentage of storage.

VPP participation by 2030 (8.9GWh for Scenarios 1-5 and 16.2GWh for Scenarios 6-10) and by 2042 (34.2GWh for Scenarios 1-5 and 58.2GWh for Scenarios 6-10).

Under Scenarios 1-5 36,178 MWs of Solar PV and 21,785MWhs of Battery Storage is assumed in 2030 and 57,374 MWs of Solar PV and 64,111 MWhs of Battery Storage is assumed in 2042. Under Scenarios 6-10 47,428 MWs of Solar PV and 39,334MWhs of Battery Storage is assumed in 2030 and 103,860 MWs of Solar PV and 108,959 MWhs of Battery Storage is assumed in 2042.

[23] For the purposes of CBA modelling the introduction of a data hub does not impact VPP participation uptake. This compounding effect is not modelled but is identified qualitatively in section 3.1.1.

DOE configurations

Table 2.3 details the DOE configurations tested in the CBA scenarios.

Table 2.3 Definitions of the DOE configurations

DOE Configurations	
Constraint Optimisation Frequency Frequency of updating the constraint optimisation settings	The frequency (**Annual, Daily** or **Intra-day**) of updating the constraint optimisation settings that would govern the safe operating distribution network limits.
DOE Customer Coverage Proportion of total DER that receive DOEs whether they are enrolled in a VPP or not	**VPP only** means only DER that is participating in a VPP would be receiving DOEs. **100%**[24] means all new DER connected to the distribution network is active and would be receiving DOEs.
DOE optimisation methodology Methodology that DNSPs use to set their DOE limits for participating DER	**LV impedance model** option involves a load flow calculation using low voltage network impedance models, customer data and operational forecasts to set these limits. **Approximation** means the DNSP, when setting the DOE limits, derives an analytical approximation of the network capacity using mainly historical network and Advanced Metering Infrastructure (AMI) data.
DOE objective function for network capacity allocation[25] The objective for the DOE calculation	**Nameplate** involves allocating DER capacity in a way where the optimal outcome is a pro-rata split of distribution network capacity based on the nameplate rating of the DER. **Maximise service** involves allocating DER capacity to the DER, with the aim to maximise the volume of export or import from them. In this approach, higher DOE will be allocated to DER facing lesser network constraints.

[24] 100% DOE Customer Coverage is intended to represent a 'bookend' and is not intended to represent an expected future.

[25] Across the CBA Scenarios two objective functions for network capacity allocation have been considered. These objective functions were selected during CBA design. The nameplate objective function was included given its assessment in the Project EDGE field trial (nameplate = approximation). The maximise service objective function was included to represent a 'bookend' whereby DER capacity is being maximised (as opposed to an equal allocation objective function).

Market Configurations

Table 2.4 details the market configurations tested in the CBA scenarios.

Table 2.4 Definitions of the market configurations

Market Configurations (see section 2.2.4 for additional detail)	
Scalable DER Data Exchange	**Point-to-point** – participants establish dedicated, bespoke connections to share data using mutually preferred methods and protocols. **Data Hub** – shared digital infrastructure allowing data exchange between participants. It is a data exchange model that enables standardised, efficient and scalable DER-related data exchange. Project EDGE assessed two implementations of a data hub, based on centralised or decentralised infrastructure.
Local Services Exchange (LSE)	The interface to facilitate visible, scalable and competitive trade of DER-based network support services for local network constraint management. Data exchange for an LSE can be via point-to-point or a data hub.

Figure 2.1 below outlines the key arrangements of each scenario[26]. The scenarios reflect a gradual increase in maturity of the selected capabilities of DER participation in the NEM, relative to the base cases.

Figure 2.1 CBA scenarios[27,28,29]

		Scenario 1 Base case	**Scenario 2** Simple DOE, Moderate Coverage	**Scenario 3** Simple DOE, Moderate Coverage with Data Hub	**Scenario 4** Advanced DOE, High Coverage	**Scenario 5** Advanced DOE, High Coverage with Data Hub
Based on AEMO ISP Step Change forecast load and DER uptake assumptions						
Dynamic Operating Envelope (DOE) configurations	Constraint Optimisation Frequency	Annual	Daily	Daily	Intra-day	Intra-day
	DOE Customer Coverage	VPP only	VPP only	VPP only	100%	100%
	DOE Optimisation Methodology	Approximation	Approximation	Approximation	LV impedance model	LV impedance model
	DOE Objective Function	Nameplate	Maximise service	Maximise service	Maximise service	Maximise service
Market configurations	Scalable Data Exchange	Point-to-point data exchange approach	Point-to-point data exchange approach and LSE	Data Hub & LSE	Point-to-point data exchange approach and LSE	Data Hub & LSE
	Local Services Exchange (LSE)					

		Scenario 6 Base case	**Scenario 7** Simple DOE, Moderate Coverage	**Scenario 8** Simple DOE, Moderate Coverage with Data Hub	**Scenario 9** Advanced DOE, High Coverage	**Scenario 10** Advanced DOE, High Coverage with Data Hub
Based on High DER forecast load and DER uptake assumptions						
Dynamic Operating Envelope (DOE) configurations	Constraint Optimisation Frequency	Annual	Daily	Daily	Intra-day	Intra-day
	DOE Customer Coverage	VPP only	VPP only	VPP only	100%	100%
	DOE Optimisation Methodology	Approximation	Approximation	Approximation	LV impedance model	LV impedance model
	DOE Objective Function	Nameplate	Maximise service	Maximise service	Maximise service	Maximise service
Market configurations	Scalable Data Exchange	Point-to-point data exchange approach	Point-to-point data exchange approach and LSE	Data Hub & LSE	Point-to-point data exchange approach and LSE	Data Hub & LSE
	Local Services Exchange (LSE)					

Legend: Maturity of DOE and market configurations

[26] Detailed information on the Project EDGE CBA 'as-built' methodology is published at https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

[27] The load and DER uptake assumptions for Scenarios 1-5 are based on AEMO, 2022 ISP (June 2022), at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en. The load and DER uptake assumptions for Scenarios 6-10 are based on Energeia (2020), Renew DER Optimisation (Stage II): Final report (for Renew), page 4 and page 32, at https://energeia.au/wp-content/uploads/2022/03/Renew-DER-Optimisation-Final-Report-210930v2_compressed.pdf

[28] To limit the number of CBA scenarios the impact of each DOE configuration tested within the CBA has not been isolated (e.g., from Scenario 3 to Scenario 4 both the DOE customer coverage and DOE optimisation methodology change).

[29] All scenarios assume 41% VPP participation as a % of storage by 2030 (8.9GWh for Scenarios 1-5 and 16.2GWh for Scenarios 6-10) and 52% VPP participation as a % of storage by 2042 (34.2GWh for Scenarios 1-5 and 58.2GWh for Scenarios 6-10).

2.1.2. General assumptions

Table 2.5 details the general assumptions underpinning the CBA.

Table 2.5 General CBA assumptions

Assumption	Detail
Period of analysis	20 years (FY23-FY42)
Base year	FY23
Discount rate	4.83%[30] [31]
Sensitivity analysis	Different discount rates (7% and 10%) and an increase in costs across key streams (e.g., generation build, operational and maintenance costs and distribution hosting capacity costs).

[30] As per AER CBA guidelines, the lower boundary discount rate should be the regulated cost of capital, based on the AER's most recent regulatory determination (as at late 2021).

[31] AER (April 2021), Final Decision AusNet Distribution Determination 2021-2026.

2.1.3 CBA market participants

Table 2.6 details the market participants considered in the CBA.

Table 2.6 CBA market participants

Assumption	Detail
DER Aggregators (grouped with DER Customers)	Groups responsible for representing many DER Customers, collectively managing devices to provide electricity services including wholesale energy (similar to VPPs). DER Aggregators can deliver multiple services on their customers' behalf, including market services to AEMO, local network services to DNSPs and hedging services to Retailers. DER Aggregators enter into commercial agreements with DER Customers to use their capacity and data to deliver services according to the customers' preferences. DER Aggregators may also be registered energy Retailers (i.e., retailers that operate their own VPPs). For the CBA, the findings of DER Aggregators and DER Customers are grouped together.
DER Customers (grouped with DER Aggregators)	Consumers with active DER. Their participation may be managed via their enrolment in a VPP or considered independently. For the CBA, the findings of DER Aggregators and DER Customers are grouped together.
DNSP (used interchangeably with Distribution System Operator (DSO))	Responsible for controlling and operating a distribution system.
TNSP	Responsible for controlling and operating a transmission system.
Market Operator	Responsible for establishing and operating the wholesale electricity market, enabling participation of generation and load, and undertaking supply demand balancing, price setting and dispatch functions in accordance with market rules and regulations. In the case of Project EDGE, the Market Operator is AEMO.
Other	Refers to broader 'whole of system' impacts (including non-DER Customers) as compared to a specific market participant.

Table 2.7 aligns the costs and benefits considered in the CBA with the market participants.

Table 2.7 Cost and benefit categories across market participants

Market Participants	Costs	Benefits
DER Aggregators and DER Customers	• DER Aggregator software platform costs – upfront and ongoing. • Scalable DER data exchange and LSE costs – upfront and ongoing data exchange platform and LSE costs. • DER visibility costs for DER Aggregators (e.g., forecasting engine, data transfer, operational functions and bid modifications).	• Avoiding DER curtailment. • Value from partial displacement of large generators via wholesale integration of active DER[32]. • Value from the provision of local network support services.
DNSPs	• DERMS software platform costs – upfront and ongoing. • Scalable DER data exchange and LSE costs – upfront and ongoing data exchange platform and LSE costs. • DER visibility costs (e.g., gathering network data and data transfers).	• Avoiding load hosting capacity costs associated with maintaining and increasing the capacity of the distribution network to meet peak demand growth without compromising the system's reliability or quality of service. • Avoiding voltage hosting capacity costs associated with increasing the capacity of the distribution network to host DER without causing voltage excursions.
TNSPs		• Avoiding load hosting capacity costs associated with maintaining and increasing the capacity of the transmission network, given energy demand growth, without compromising the system's reliability or quality of service.

[32] This results in the reduction of generation costs (e.g., build, operational and maintenance costs) needed to meet energy demand across the NEM. This is partially enabled by more advanced DOEs and greater active participation of DER in VPPs, and it is therefore assumed DER Aggregators will capture some of the value associated with this.

Market Operator	• Scalable DER data exchange and LSE costs – upfront and ongoing data exchange platform and LSE costs (under a centralised data hub only). • DER visibility costs (e.g., forecasting short term network state and NEM 2025 Work Package 2 Visibility).	• Reduced risk of Reliability and Emergency Reserve Trader (RERT) and load shedding events.
Other (categories that refer to broader 'whole of system' impacts (including non-DER Customers) as compared to a specific market participant.)	• FCAS costs – provision of contingency and regulation FCAS.	• Reduced emissions ($CO2e$[33]) associated with electricity generation. • Reduced risk of severe and costly system black events due to greater Market Operator and DNSP visibility and control of DER.

[33] CO2e is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential, by converting amounts of other gases to the equivalent amount of carbon dioxide with the same global warming potential.

2.2 CBA Tools

This section details the CBA workflow across the range of tools and activities utilised in the CBA.

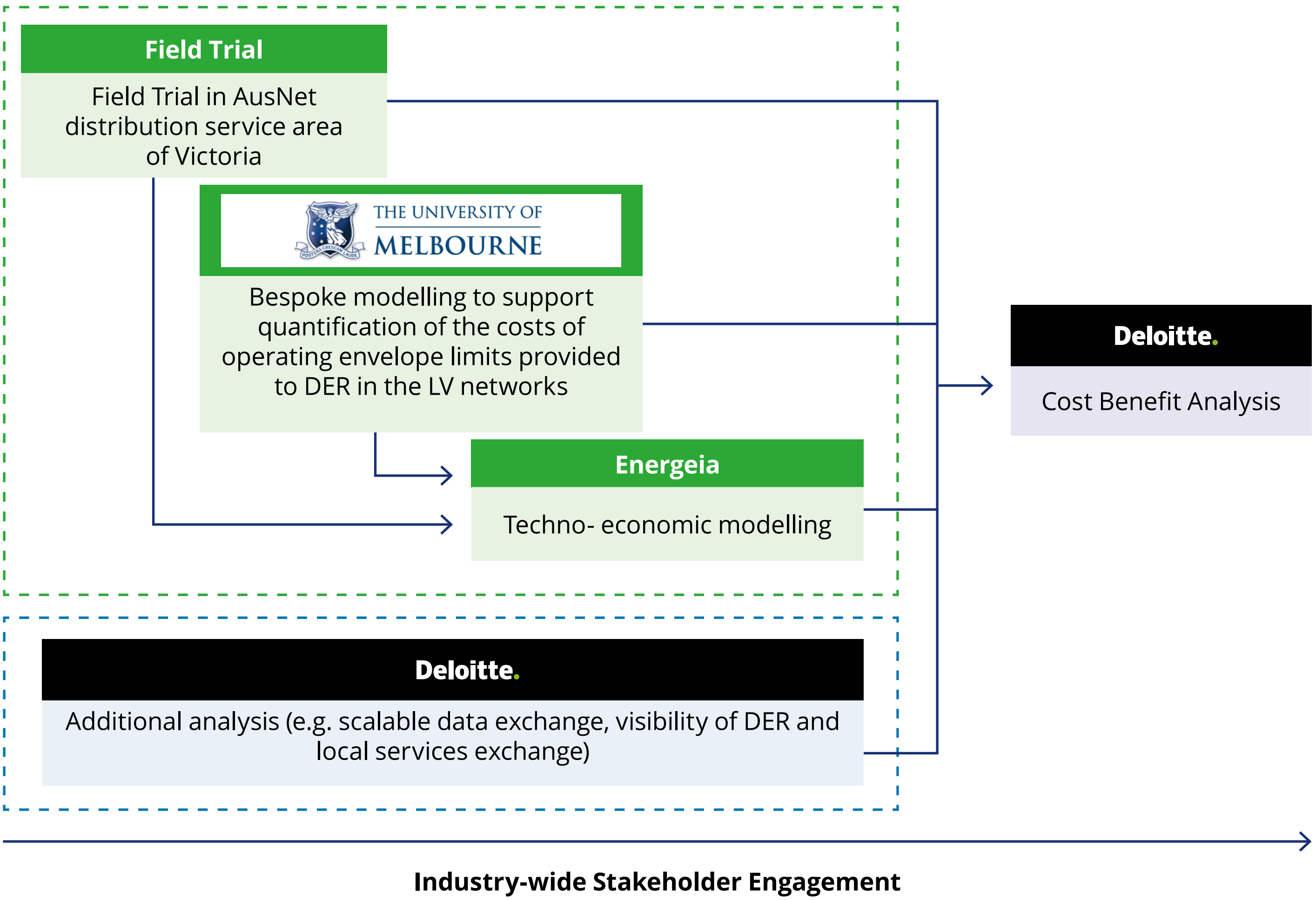
It should be noted that the integration of DER into the NEM is highly complex and subject to many variables.

While we have made all efforts to ensure inputs and assumptions are based on the best available information, in this context it is important to consider the nature of DER, customer behaviours, technological advancements, the physical energy system, energy policy and regulation are all rapidly changing.

Sections 2.2.1 - 2.2.4 detail the range of tools and activities utilised in the CBA to assess an end-to-end market arrangement for coordinating DER to provide both wholesale and local network services within the constraints of the distribution network.

These tools and activities were selected to best use market inputs to test the outcomes of the Project EDGE field trial under 'as real' conditions of the NEM at the time of quantification.

Figure 2.2 CBA workflow overview



2.2.1 Techno-economic modelling (TEM)

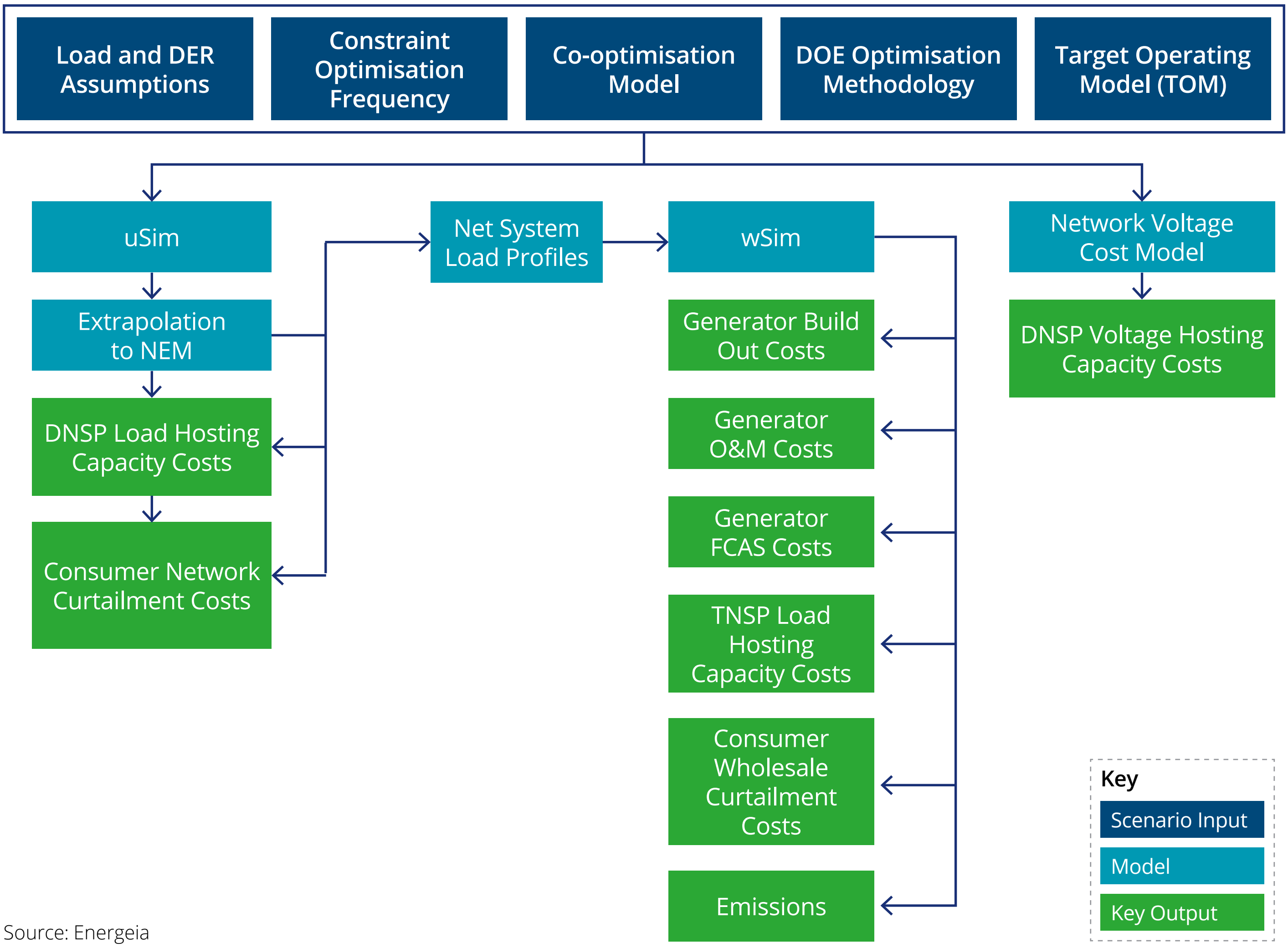
Energeia was engaged to support development of the CBA via TEM, using the following whole-of-system modelling sub-platforms:

- Utility Simulator (uSim) – models customer behaviour – including transport and building electrification, DER adoption and operation, 17520 load and DER profiles (half-hourly intervals for a full year), distribution network assets, and network and retail tariffs – by DNSP, year and scenario.
- Wholesale Market Simulator (wSim) – models NEM Regional Reference Prices (RRPs), security constrained economic dispatch and capacity expansion, by state, year, and scenario.

In addition, network voltage hosting capacity costs were calculated using a bespoke Network Voltage Cost Model developed for the CBA.

The relationship between the models and outputs is illustrated in Figure 2.3.

Figure 2.3 TEM output relationship



Source: Energeia

The remainder of this section summarises each Energeia TEM sub-platform.

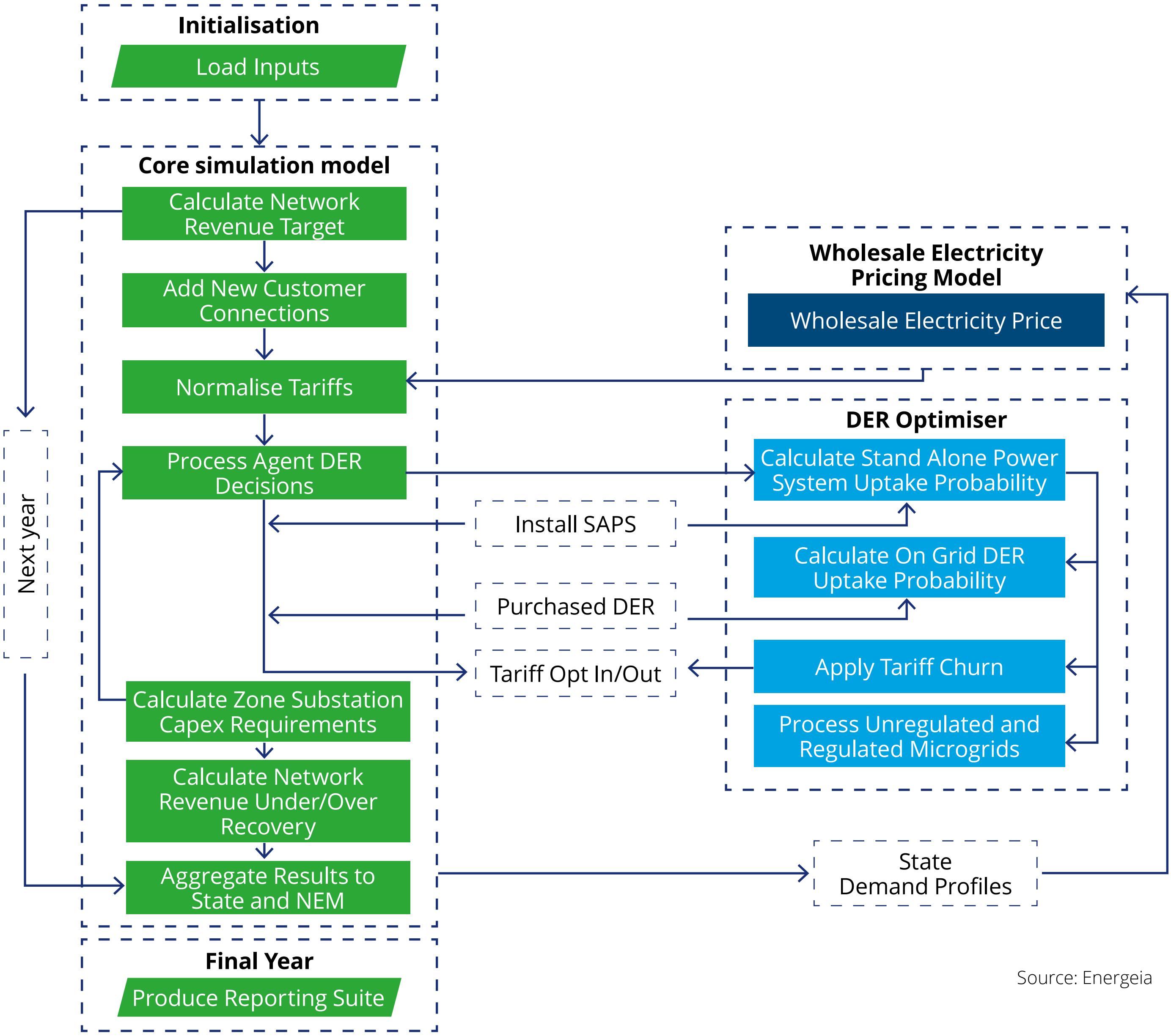
Utility Simulator (uSim)

uSim is a bottom-up, agent-based[34] model that simulates how consumers make decisions with respect to fuel substitution, energy efficiency and DER investment and operation, under different policy, regulatory, tariff, technology, and macro-economic settings.

It also estimates the corresponding impact of customer decision making on electricity networks, transport, gas sectors and wholesale markets.

uSim operates through an iterative process year-on-year, for each year of the simulation period, working through the process loops shown in Figure 2.4.

Figure 2.4 Overview of Energeia's energy system simulation platform (uSim)



Source: Energeia

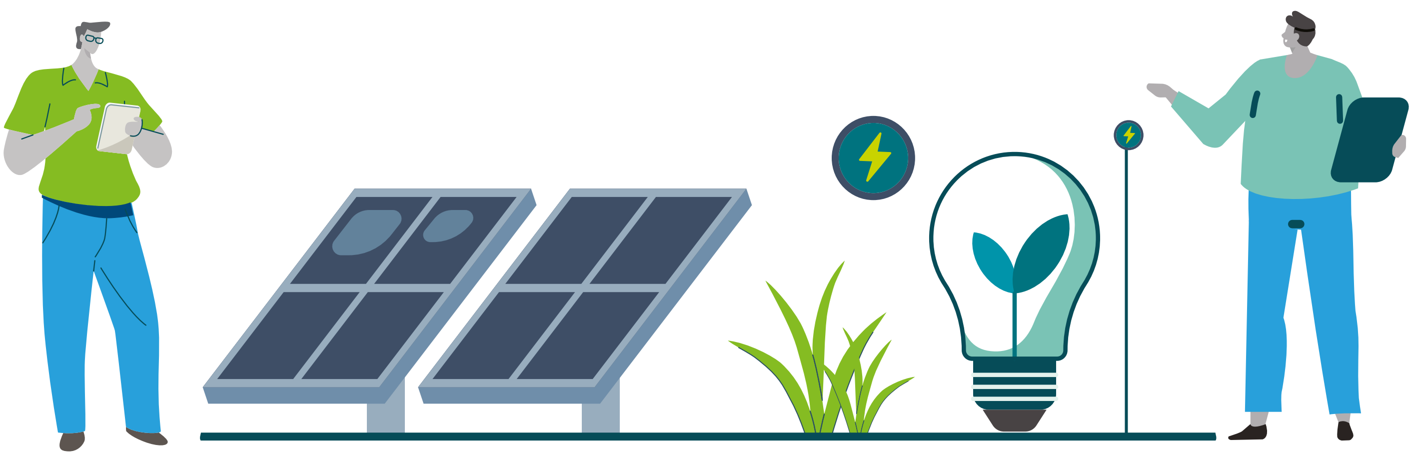
[34] Agents are the principal decision makers within the simulations. It is the decisions that agents (and the consumers they represent) make that drive network decisions, energy prices and the outcomes of the grid.

uSim simulates the customer base represented by a sample set of agents. Each year, these consumers make economic decisions to optimise their electricity bill, including changing tariff structure, adopting solar and storage, purchasing an EV, electrifying gas appliances or adopting more energy efficient appliances. These decisions impact that customer's use of the network.

The resulting load profiles are aggregated to each network asset, where investment decisions are made, where reliability constraints arise, to augment or replace existing network assets to satisfy load or generation hosting requirements. Finally, the revenue requirements of the network are determined, and tariffs are normalised to satisfy the revenue requirements of each customer class. The change in wholesale cost is also accounted for in this recalculation.

For the CBA, uSim simulated the AusNet distribution service area using customer, network HV and sub-transmission load data provided by AusNet to enhance the accuracy of the findings. The level of DER uptake simulated was calibrated according to the specifications within each CBA scenario. DER limits were modelled at the customer level and determined by the amount of DER market penetration each year and DOE configurations considered within each CBA scenario. The parameters that defined the limits set were informed by UoM[35].

The impacts of the scenario settings on the AusNet network outcomes were extrapolated to state load profiles by applying the relationship between DER uptake and the level of curtailment at AusNet over a full year's load profile to each DNSP.



[35] UoM undertook modelling that has been used to inform Energeia's TEM. Specifically, UoM's modelling has been used to support quantification of operating envelope limits provided to DER in the LV networks. UoM provided data sets from three representative LV networks (city, suburban, and regional). The city and suburban networks were sourced from CSIRO which clustered approximately 71,000 LV networks into 23 representative LV networks. The regional network was based on one of the regional networks being tested in the Project EDGE field trials.

Wholesale Market Simulator (wSim)

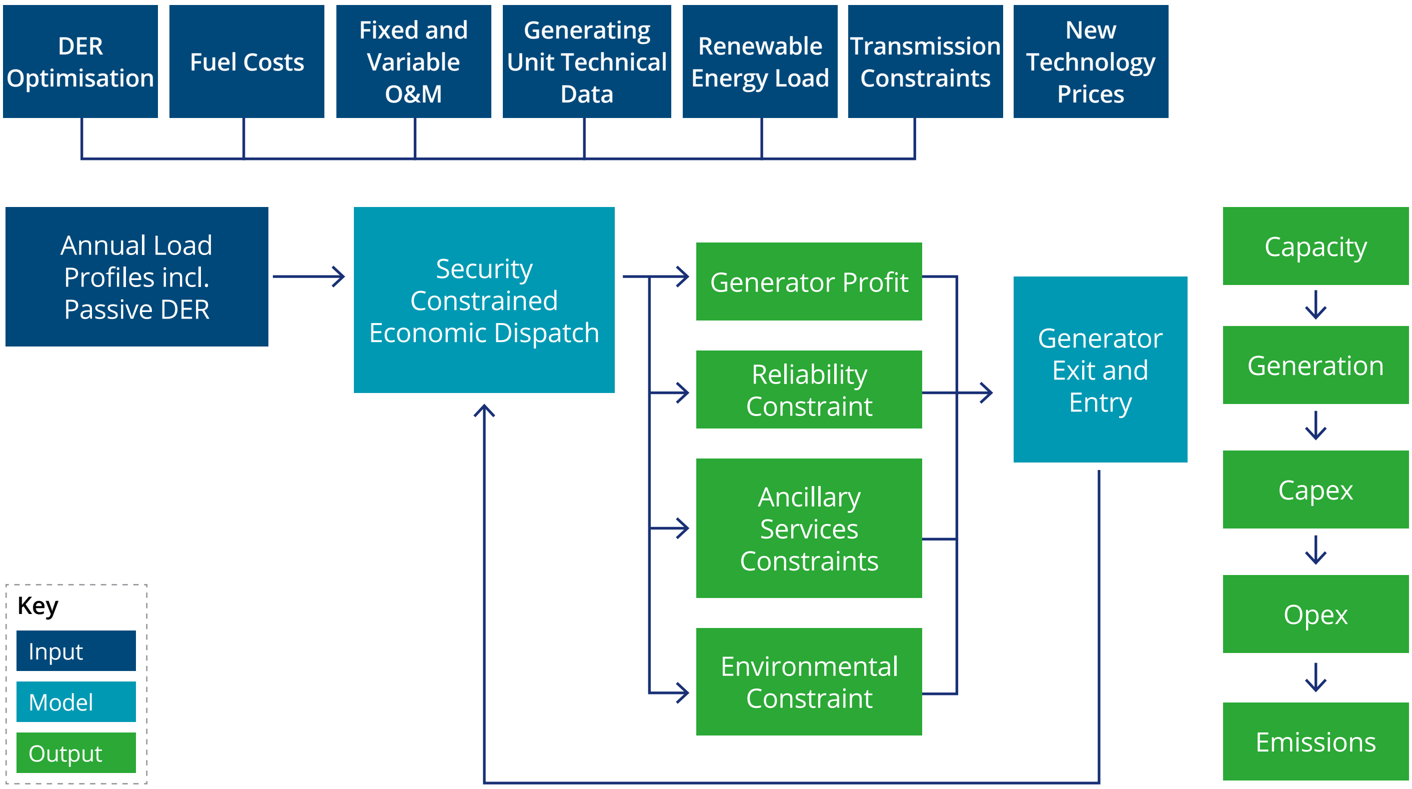
wSim provides a simulation of the NEM Security Constrained Economic Dispatch (SCED) and calculates the associated price of energy, ancillary services and key generator revenue streams, its structure is depicted in Figure 2.5.

Annual operational load from the AEMO ISP Step Change was used. The level of behind the meter (BTM) DER is determined based on the scenario being modelled, as is the percentage of active DER. The profile of DER is first curtailed to simulate network constraints based on the uSim modelling.

The SCED[36] of resources and associated clearing prices are then determined for each year given the relative costs[37] of each resource type. This includes DER coordination through VPPs, which involves the shifting of active EV charging, electric water heater and BTM DER.

The resulting generator profits and prices are used to determine generator exit and entry, and the SCED step is repeated until there is no more economic entry or exit and the solution meets all specified reliability, ancillary services and environmental constraints[38].

Figure 2.5 Overview of Energeia's integrated energy system simulation platform (wSim)



Source: Energeia

[36] Security constrained means that dispatch is subject to transmission and operational constraints.
[37] Strategic bidding was not used for the CBA.
[38] Least cost solutions to environmental, ancillary services and reliability constraints are identified using the SCED process.

For the CBA, wSim simulated the SCED and capacity expansion of all regions within the NEM by assuming that resources bid into the market at their short run marginal cost (SRMC). This excluded coal generation, which was able to bid negative prices at minimum stable level of operation to prevent switching off. This effectively means that generator resources cleared the market on a least-cost basis, rather than bidding strategically to maximise profits.

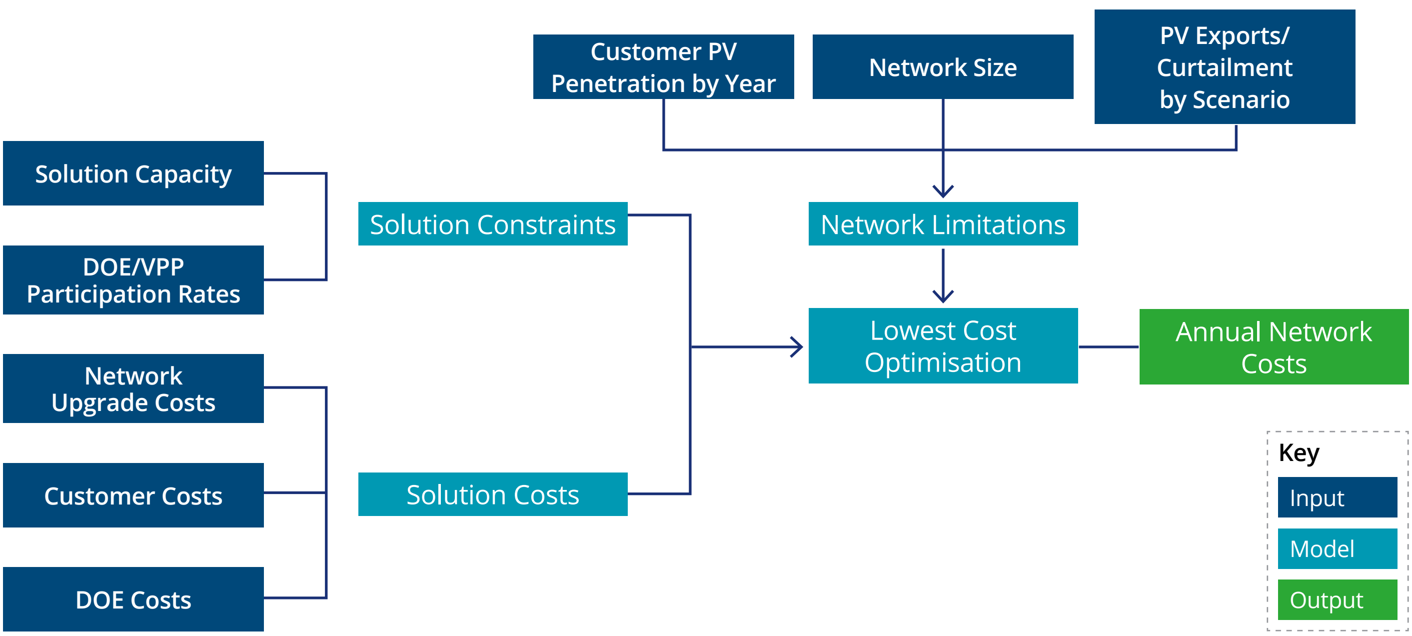
In addition to dispatching electricity in the wholesale market, generators are also able to participate in ancillary services markets that contribute to market reliability, including regulation FCAS[39] and contingency FCAS[40].

For each interval modelled, wSim estimates ancillary service demand and generator bidding to determine the price received per MWh for the service. The wSim model ensures that sufficient ancillary services are available for 5% of load for forecasting error, single generator or interconnector contingency and ramping capacity.

Network Voltage Cost Model

The Network Voltage Cost Model identifies the least cost pathway to address voltage issues caused by hosting DER on the distribution LV network using a bottom-up approach. It considers a typical LV asset and a range of solutions available to increase DER hosting capacity on the asset, as uptake increases over time, while maintaining reliability standards. This process is shown in Figure 2.6.

Figure 2.6 Overview network voltage cost model



Source: Energeia

[39] Response to minor changes in frequency, estimated based on total grid load serviced by dispatchable capacity at a given interval.

[40] Response to major changes in frequency, estimated based on the change in grid load from the previous interval.

The single-asset outcomes of the modelling are then extrapolated to the network level based on the number of consumers on that network.

The model considers a single typical distribution LV asset on a given network and forecasts the marginal hosting capacity increase required in each year, considering the level of DER uptake of each DNSP.

The model then identifies available solutions to enable sufficient DER hosting capacity in the distribution network. This includes identifying available solutions, their capacity to meet marginal exports in the network, and the costs of each solution to both the DNSP and consumers.

Finally, the lowest cost solution is determined to meet the hosting capacity needs of the network in each year, considering the availability, capacity, and cost of each solution, including the cost to the customer. Ultimately, this drives the level of expenditure required by the network annually.

2.2.2 UoM modelling of dynamic operating envelopes

UoM undertook modelling that was used to inform Energeia's TEM. Specifically, UoM's modelling was used to support quantification of the DOE limits provided to DER in the LV networks.

UoM provided data sets from three representative LV networks (city, suburban, and regional). The city and suburban networks were sourced from CSIRO[41] which clustered approximately 71,000 LV networks into 23 representative LV networks. The regional network was based on one of the regional networks being tested in the Project EDGE field trials.

To align with the CBA, the two sets of DER uptake assumptions used across the CBA scenarios were used by UoM.

2.2.3 Project EDGE field trial

Data from the Project EDGE field trial was used when validating Energeia's TEM DOE impacts, by considering how they have worked in practical application under a variety of conditions, as opposed to what the modelling forecasts under perfect information (e.g., ensuring that an appropriate forecasting error was considered). For example, on a given feeder, 200 kW of network capacity may have been predicted by the DOE to be available for the day ahead, but in actuality 220 kW was available.

2.2.4 Additional areas of analysis in the CBA

The Energeia TEM was supplemented with additional modelling focused on scalable DER data exchange, LSE and visibility of DER. The section below outlines the methodology underpinning these areas.

Scalable DER Data Exchange

To support the integration of DER in the NEM, the scalable DER data exchange approaches considered must allow at a minimum, the following use cases:

- DER Register – an accurate and dynamic registry of all DER located across all distribution networks.
- Identity and Access Management (IDAM) – digital IDs for participant and device IDAM within data exchange.
- DOEs – enabling DNSPs to offer a new dynamic export/import limit option to DER Customers.
- LSE.

The CBA has identified three scalable DER data exchange approaches for evaluation.

[41] CSIRO (Nov 2021), at https://publications.csiro.au/publications/publication/PIcsiro:EP2021-2759

Point-to-Point (standardised)

Integration is required between each participant participating in the facilitation of DER use cases:

- A do-nothing scenario applied to DER, where new use cases are implemented in absence of a data hub, with the application of agreed industry standard communication processes and terminology among participants.
- Each customer agent would be required to verify their identity and maintain a register of their portfolio with each DNSP.
- Data models (as they relate to bespoke internal systems), software and hardware architectures, and integration methods can differ between DNSPs.

Centralised Data Hub

Each participant only needs to integrate with the data hub once:

- Data is exchanged through a centralised data hub via a centralised broker (assumed in Project EDGE[42] to be AEMO) that operates the hub and receives and transfers data according to agreed rules.
- Centralised governance is streamlined with industry input, and existing standardised processes are centralised within AEMO.

Decentralised Data Hub

As with the Centralised Data Hub, each participant only needs to integrate with the data hub once. However, a Decentralised Data Hub:

- Removes the need for a centralised broker role, both in terms of hosting the hub and in operating the hub to transfer data through it.
- Facilitates a shared governance and ownership model with the aim of increasing opportunities for participants to innovate and deliver services to DER customers.

A data hub approach to scalable DER data exchange is assumed across Scenarios 3, 5, 8 and 10. Each of these scenarios is tested with a centralised and decentralised data hub. All other scenarios assume a point-to-point approach.[43]

Local Service Exchange (LSE)

Within Project EDGE the LSE acts as the interface for DER Aggregators and DNSPs to trade local network support services[44]. This includes the submission of offers, exchange of contracts, delivery of the service and the settlement of transactions.

The LSE is considered as the transaction mechanism for the provision of services to DNSPs on a local level, as distinct from the system-wide wholesale markets managed by AEMO.

The Project EDGE field trial[45] focused on the technical requirements of an LSE – specifically demand management and voltage management services.

The CBA[46] assessed the LSE under different scalable DER data exchange approaches.

- Scenarios 3, 5 ,8 and 10 assume the LSE is facilitated on the data hub.
- Scenarios 2, 4, 7 and 9, under a point-to-point arrangement to scalable DER data exchange, assume each DNSP seeks to establish its own LSE and associated data exchange integrations with each participating DER Aggregator.

[42] AEMO being the central broker is consistent with AEMO's current role in the NER for operating the Retail Market Business to business (B2B) eHub.

[43] This CBA assumes for the purposes of assessing the scalable DER data exchange approaches that there will be 13 DNSPs by FY42 each integrating with on average 27 DER Aggregators/Retailers/Original Equipment Manufacturer (OEM) and assumes that there will be 52 DER Aggregators/Retailers/OEMs by FY42 (29 in FY23 and 45 in FY30) each integrating with on average 6 DNSPs. The number of DER Aggregators/ Retailers/OEMs has been informed by the current number of market participants in the NEM currently offering VPPs, the NEM Registration and Exemption List and the VPP uptake assumptions used in this CBA. It is assumed that not all DER Aggregators/Retailers/OEMs using the DER data exchange will participate on the spot market (e.g., some will only be using the DER data exchange for the purposes of FCAS and business-to-business (B2B) services).

[44] AEMO is not included in the bilateral trade of local services between DNSP and DER Aggregator.

[45] The economic value of the LSE was not tested via the Project EDGE field trial. The field trial was focused on assessing the technical requirements of the LSE.

[46] This CBA assumes for the purposes of assessing the LSE that there will be 13 DNSPs by FY42 each integrating with on average 7 DER Aggregators/Retailers/OEMs and assumes that there will be 13 DER Aggregators/Retailers/OEMs by FY42 (0 in FY23 and 12 in FY30) each integrating with on average 3 DNSPs.

Visibility of DER

Visibility refers to knowing where DER are installed on the network and how they behave to improve situational awareness and forward-looking operational and network planning such that more accurate (and less conservative) operations can occur across the electricity market. It is relevant to the roles of the Market Operator, DNSPs and DER Aggregators.

The CBA focused on the incremental costs and benefits for market participants in shifting from a defined **current state** (i.e., before Scheduled Lite[47] and SCADA Lite[48] implementation) where there is visibility of DER based only on:

- DER participating in the wholesale demand response (WDR) mechanism[49]
- Demand side participation information portal, and
- the DER Register

to a **future state** where DER in VPPs is fully scheduled ('visibility with controllability') and aligned with appropriate technical and performance standards. It is assumed that with DER being fully scheduled, that DER Aggregators provide the Market Operator with a 20-band bi-directional offer (10 for load, 10 for generation) which is used to clear the market (informing DER Aggregators of their dispatch volumes).

In the CBA, the base cases assume alignment with the defined current state, while all other scenarios assume alignment with the defined future state. The costs and benefits are limited to those directly associated with the defined uplift from current state to future state in visibility of DER.

In addition, the costs of two bidding modes (definition of power quantity (kW) submitted in the bi-directional offer) were considered to show the impact of differing measurement points[50]:

- Net NMI – measured at the connection point (NMI-level) and aggregated across the DER Aggregator's portfolio, including both controllable and uncontrollable generation and load
- Flex – measured at a common measurement point, representing the aggregation of all controllable DER assets at a site and aggregated across the DER Aggregator's portfolio. Flex does not include uncontrollable customer load and generation at a site, as these resources are already accounted for in the Market Operator operational forecasts. Flex focuses on the sum of all controllable devices (load and/or generation) across the portfolio of NMIs (as shown in Figure 2.7).

[47] AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite

[48] SCADA Lite is part of the NEM 2025 roadmap and has been identified as a foundational initiative. SCADA Lite aims to reduce entry barriers for smaller generators and demand side resources to provide greater visibility to AEMO and to participate in the market with SCADA that is fit for purpose for DER.

[49] The WDR mechanism allows demand side (or consumer) participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. The WDR Mechanism has a range of eligibility requirements including customer load size.

[50] Primarily from the perspective of the Market Operator, however the cost to DER Aggregators associated with modifying the bid file (e.g., from Net NMI to Flex or vice versa) was included.

Figure 2.7 Flex vs Net NMI functions

FLEX

Controllable (Load and/or Generation) :

Sum of controllable devices (load and/or generation; not individual devices) across the participant's registered portfolio of NMIs

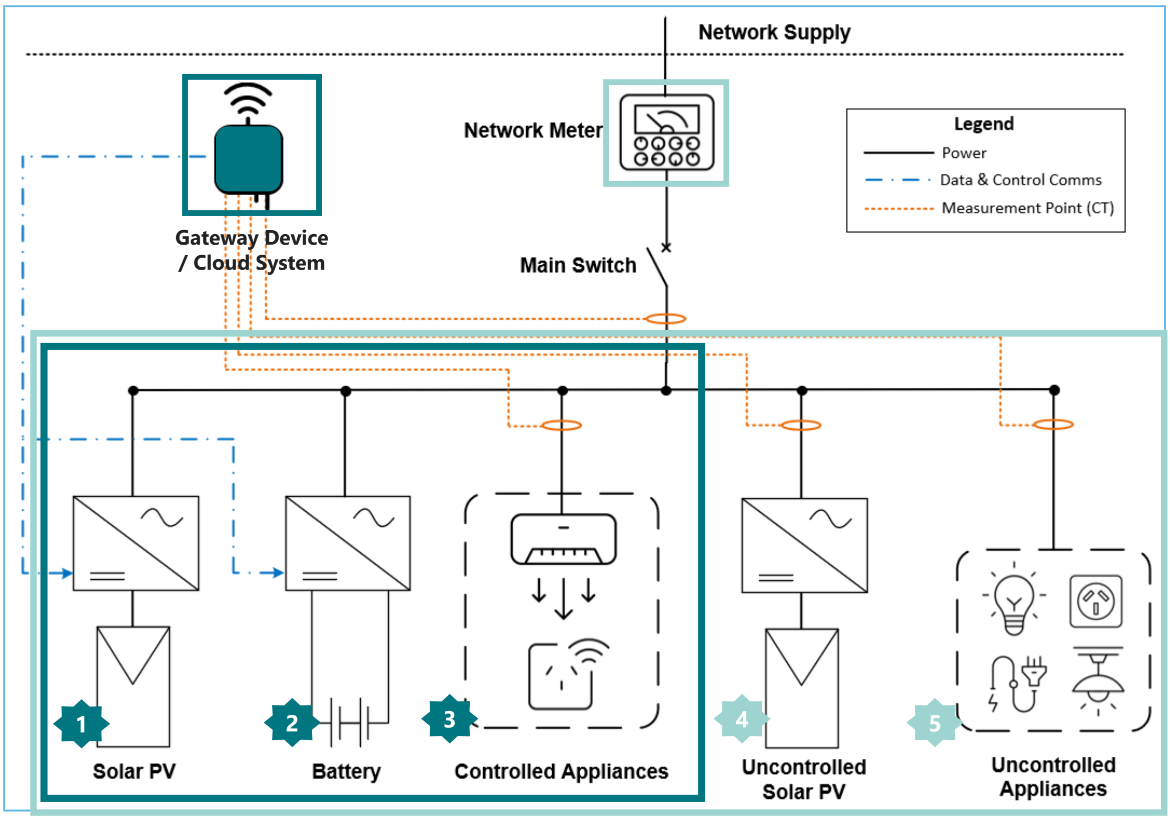
- Only controllable assets are considered when calculating the controllable only capacity.
- Measurement at a real/virtual measurement point. This is aggregation of all controllable devices at a common measurement point. Not individual devices.
- Visibility of 'aggregation' of all controlled assets is provided via Bids and DUID Telemetry.
- Total of (1 + 2 + 3)

NMI

Aggregated Net Connection Point Flow:

Sum of net connection point flows across the participant's registered portfolio of NMIs i.e. Net at NMI

- All Controllable and un-controllable assets considered when calculating the net connection point flow value
- Measurement at Connection point (i.e. NMI).
- Visibility of net position at NMI is provided via Bids and DUID Telemetry. Separation of controlled and uncontrolled assets is not required or visible.
- Total of (1 + 2 + 3 + 4 + 5)



Source: Project EDGE participants (AEMO, AusNet and Mondo).

2.3 Stakeholder Engagement

Stakeholder engagement was a critical activity for the CBA. It was essential that the inputs and assumptions that underpin them were refined independently, in line with stakeholder views, and reflected where possible the latest information available.

For the CBA, stakeholders were consulted directly through:

- Presentations to forums facilitated by the Project EDGE participants such as:
  - The Demonstration Insights Forum (DIF): a panel of industry experts providing feedback on project design and implementation
  - The Network Advisory Group (NAG): a panel of distribution network stakeholders led by AusNet, facilitating discussion and feedback on network specific aspects of projects
  - The Market Integration Consultative Forum (MICF): a Retailer and DER Aggregator focused forum engaging stakeholders on integration topics to provide feedback on arrangements that support DER integration
  - The Consumer Engagement Forum: a community and customer group engagement, intended to gauge viewpoints of consumers
- Targeted consultations via 1:1 meetings or correspondence.

A key stage of consultation was on the draft CBA methodology from July 2022 to September 2022. Engagement with a broad range of stakeholders on the Draft CBA Methodology Report provided an early opportunity to test and challenge the robustness of the approach and underlying assumptions, as well as a means of capturing additional information and views on methodology inputs, including costs and benefits.

Stakeholder Groups

The stakeholders that were consulted for the CBA component of Project EDGE are a subset of the overall project stakeholders. They are categorised into three groups.

Group 1 stakeholders are energy industry institutions that shape the Australian energy market structure and operating environment now and will into the future. These stakeholders include:

- The Project EDGE participants
- Australian Renewable Energy Agency (ARENA)
- Australian Energy Market Commission (AEMC)
- Energy Security Board (ESB)
- Australia Energy Regulator (AER)
- Energy Networks Association (ENA)
- Energy Consumers Australia (ECA).

Targeted one-on-one consultations occurred with Group 1 stakeholders.

Group 2 stakeholders are energy market participants represented in Project EDGE whose engagement was required to shape CBA inputs and who have unique considerations or conditions, including:

- DNSPs, including those involved in other DER trials
- DER Aggregators
- Consumer groups.

The methods of consultation for Group 2 stakeholders included presentations at forums and data collection. One-to-one consultations were also held as required.

Group 3 stakeholders include key groups whose expertise and broader energy market knowledge was valuable, including:

- Researchers
- Peak bodies and local community groups
- Industry (including global Subject Matter Experts (SMEs)).

Group 3 stakeholders were consulted through the Project EDGE forums or through 1:1 consultation where relevant.

Prior to final findings, validation of outputs was completed with stakeholders.

Market Sounding

The CBA has utilised cost inputs from the Project EDGE participants, DER Aggregators participating in Project EDGE, non-participating DER Aggregators and technology vendors.

These costs were further validated and tested, where practical, with stakeholders through the process of engagement and from Project EDGE field trial outcomes.

Overall, the CBA approach and methodology adopted allowed for a detailed assessment of a range of scenarios under which DER participation within the NEM could deliver the long-term interests of electricity consumers across a 20-year time horizon (FY23-FY42).

3
CBA Findings

CBA Findings

Market-based DER integration is in the long-term interests of all consumers. Broad DOE coverage, scalable DER data exchange and local services enable this value by unlocking network capacity for Virtual Power Plants to coordinate DER at lower cost.

The CBA found that all consumers – including those without DER – will benefit from a coordinated, market-based approach to DER integration within the NEM. Timely implementation and careful prioritisation are required to make these benefits a reality.

This section details the CBA findings across the 20-year time horizon in terms of:

- Whole-of-system, across each scenario (in comparison to the base cases)
- Market participants (in comparison to the base cases)
- Selected capabilities of DER participation in the NEM (e.g., scalable DER data exchange, LSE and visibility of DER)

3.1 Overall Findings

Benefits to consumers are shown via an incremental benefit across all scenarios in comparison to the base cases over the 20-year time horizon (see Figure 3.1).

The findings show quantitatively that NEM via the Project EDGE arrangement can result in an incremental benefit to all consumers of up to $5.15b[51] under the AEMO ISP Step Change DER uptake assumptions and up to $6.04b[52] under the High DER uptake assumptions.

The Project EDGE arrangement of roles and market configurations was found to avoid 15.1TWh of customer rooftop solar curtailment to 2030 and up to 90.6TWh across the 20 year time horizon to 2042 under the AEMO ISP Step Change DER uptake assumptions. It was found to avoid 50.1TWh of customer rooftop solar curtailment to 2030 and up to 257.1TWh across the 20 year time horizon to 2042 under the High DER uptake assumptions.[53]

Based on the capabilities tested within the CBA scenarios, the benefits are driven by:

- DOE configurations that enable high customer coverage and target maximum utilisation of the distribution network by DER and VPPs
- Data hub approach to a scalable DER data exchange that reduces integration costs and allows access to a greater scope of service opportunities for DER Aggregators serving customers
- LSE providing a scalable and standardised market configuration for DNSPs to procure network support services from DER Aggregators, who co-optimise network support services and wholesale services within their DER portfolio
- Visibility of DER for the Market Operator and DNSPs to improve their awareness of where DER are installed on the network and how they behave to enhance situational awareness, operational forecasting, and network planning functions. Ultimately, reducing costs via enabling more accurate (and less conservative) operations across the network.

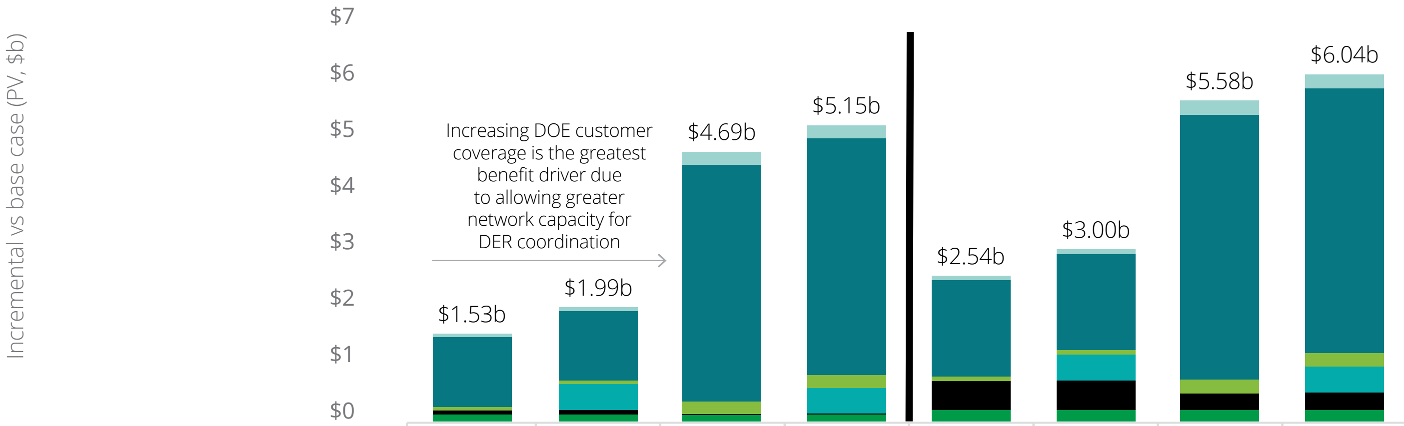
Active DER participation in VPPs is critical to realise the benefits associated with the capabilities assessed within the CBA scenarios. This will enable DER to make a coordinated response to market prices and system security events at scale.

[51] Scenario 5 - Advanced DOE, High Coverage with Data Hub (AEMO ISP Step Change).

[52] Scenario 10 - Advanced DOE, High Coverage with Data Hub (High DER).

[53] The CBA analysed curtailment of customer DER exports due to distribution network constraints by simulating the impacts of the DOE configurations (this represented the majority of analysed curtailment). In addition, wholesale market curtailment was assumed to occur when additional DER generation export would push operational demand beyond the minimum operational requirement of the NEM power system, thereby resulting in the need to curtail generation from DER, which would be done through a VPP or DOE arrangement b) For broader assessment of variable renewable energy curtailment see page 47 in the 2022 AEMO ISP.

Figure 3.1 CBA findings – key drivers of value incremental to the base cases (20-year time horizon, $FY23, 4.83% discount rate)[54]



Key drivers of value across the CBA Scenarios	**Scenario 2** (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
DOE Constraint Optimisation Frequency (more total network capacity unlocked for DER coordination)	$0.06	$0.06	$0.22	$0.22	$0.08	$0.08	$0.24	$0.24
DOE Customer Coverage (more total network capacity unlocked for DER coordination)	$1.21	$1.21	$4.12	$4.12	$1.67	$1.67	$4.60	$4.60
DOE Objective Function (more network capacity allocated to DER)	$0.06	$0.06	$0.22	$0.22	$0.08	$0.08	$0.24	$0.24
Data Hub (reduced costs and enables additional DER services)	$-	$0.45	$-	$0.45	$-	$0.45	$-	$0.45
LSE (reduced DER curtailment)	$0.07	$0.08	$0.00	$0.01	$0.50	$0.51	$0.29	$0.30
Visibility of DER (enhanced power system operations)[55]	$0.12	$0.12	$0.12	$0.12	$0.20	$0.20	$0.20	$0.20

Notes: Total power system cost in Scenario 1 is $192.7B and in Scenario 6 is $190.2B. This total cost is the cost that forms the basis of the incremental present value impact shown across the scenarios. Total indicative implementation costs for the Project EDGE arrangement for the Market Operator, DNSPs and DER Aggregators is $0.92b under Scenario 3, $1.35b under Scenario 5, $2.09b under Scenario 8 and $3.94b under Scenario 10.

[54] Scenarios 2-5 are compared to Scenario 1, while Scenarios 7-10 are compared to Scenario 6.

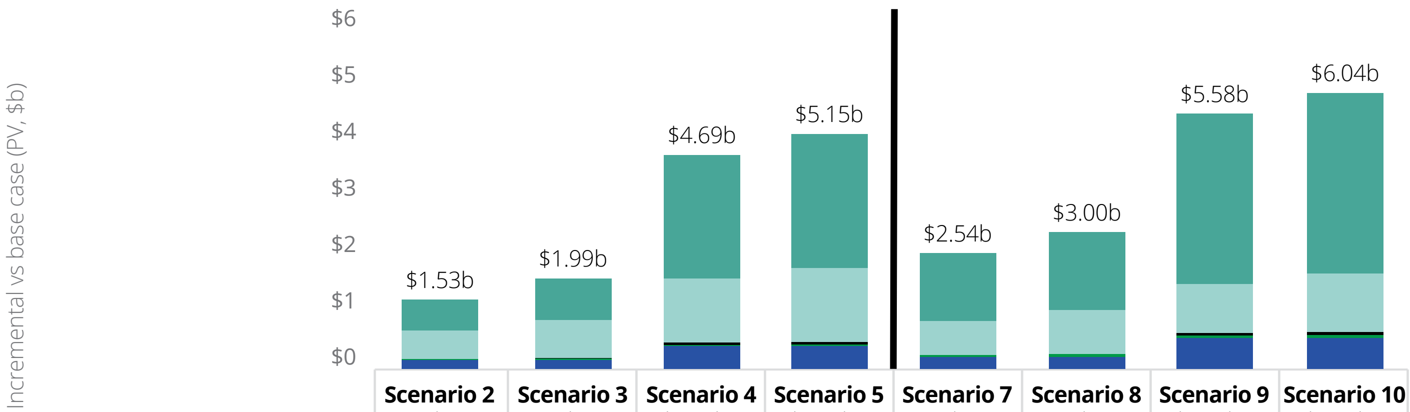
[55] Assuming Flex bidding mode.

The CBA aligns costs and benefits to market participant types. The CBA findings across market participants show:

- Increased revenue opportunities for DER Aggregators and as a consequence, DER Customers, due to:
  - a reduction in DER export curtailment,
  - partial displacement of large generators enabled via wholesale integration of active DER ,
  - the provision of contingency Frequency Control Ancillary Services (FCAS) and local network support services
  - reduced data exchange costs
- Lower DNSP costs in maintaining and increasing the capacity of the distribution network and reduced data exchange costs
- Lower TNSP costs in maintaining and increasing the capacity of the transmission network
- Lower Market Operator costs through reduced data exchange costs and enhanced management of power system security issues due to greater visibility of active DER.

Figure 3.2 outlines the CBA findings across these market participants noting that all consumers can benefit from the accelerated and optimised integration of active DER via VPPs in the NEM.

Figure 3.2 CBA findings across key market participants (20-year time horizon, $FY23, 4.83% discount rate)[56 57]



Key drivers of value across the CBA Scenarios	Scenario 2 (Simple DOE, Moderate Coverage)	Scenario 3 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 4 (Advanced DOE, High Coverage)	Scenario 5 (Advanced DOE, High Coverage with Data Hub)	Scenario 7 (Simple DOE, Moderate Coverage)	Scenario 8 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 9 (Advanced DOE, High Coverage)	Scenario 10 (Advanced DOE, High Coverage with Data Hub)
DER Aggregators (includes Retailer VPPs) and DER Customer	$0.68	$0.90	$2.70	$2.93	$1.48	$1.71	$3.73	$3.95
DNSPs	$0.62	$0.84	$1.41	$1.62	$0.74	$0.96	$1.07	$1.28
TNSPs	$0.00	$0.00	$0.06	$0.06	$0.00	$0.00	$0.06	$0.06
Market Operator	$0.02	$0.04	$0.02	$0.04	$0.05	$0.07	$0.05	$0.07
Other (FCAS and Visibility of DER)	$0.20	$0.20	$0.50	$0.50	$0.26	$0.26	$0.68	$0.68

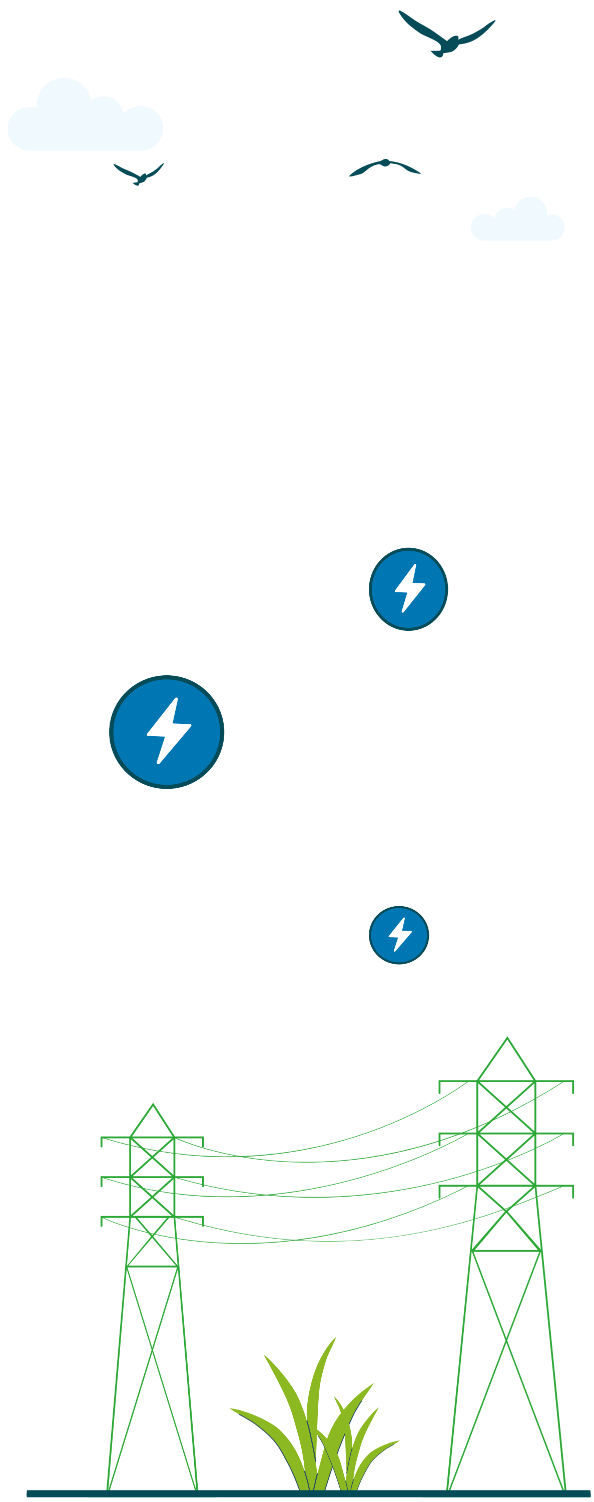
Notes: Total power system cost in Scenario 1 is $192.7B and in Scenario 6 is $190.2B. This total cost is the cost that forms the basis of the incremental present value impact shown across the scenarios.

[56] This figure assumes that DER Aggregators capture all the value of displacing large generators enabled by more advanced DOEs and greater active participation of DER in VPPs and all value associated with the delivery of local network support services. In reality, DER Aggregators would likely capture a significant portion but not all of this value.

[57] 'Other' relates to broader 'whole of system' impacts as compared to a specific market participant.

3.1.1 Additional emerging customer benefits

The CBA provides a conservative estimate of the benefits as there are several additional qualitative benefits not accounted for in the CBA due to limitations in data availability. These include:



Vehicle to Grid (V2G) coordination – given the increasing uptake of electric vehicles (EVs) in Australia58, V2G (EV charging and discharging into the grid) is expected to increase the opportunity and value associated with coordinated DER participating in a VPP (due to more DER capacity to coordinate). The CBA does not quantitatively consider the impact of V2G given its nascency at the time of project design, however it is expected that further value realisation will be possible from the coordination of greater DER capacity.

Compounding effect of market configurations on DER uptake – the effective integration of DER into the NEM via market configurations (e.g., scalable DER data exchange and LSE) that enable cost reductions or access to a greater scope of service opportunities for DER Aggregators could result in direct or indirect incentives to install more DER and increase VPP uptake.

Additional DER services – effective market configurations have the potential to facilitate further value from DER as industry maturity and needs evolve by enabling new DER-based service innovations to be more easily adopted. For example, a data hub could support additional transactions as the industry evolves and innovates such as Retailers requesting DER Aggregators to manage DER exports and hedge their exposure during periods of negative prices.

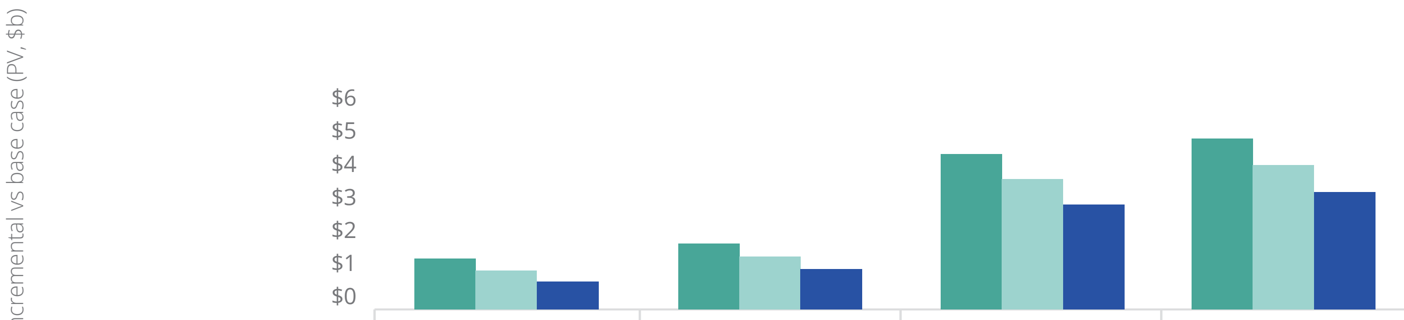
[58] As of the end of June 2023, 46,624 EVs had been sold in Australia – almost 3 times higher than the same period in 2022 (a 269% increase). Electric Vehicle Council, State of Electric Vehicles (July 2023), at https://electricvehiclecouncil.com.au/wp-content/uploads/2023/07/State-of-EVs_July-2023_.pdf

3.1.2 Sensitivity analysis

Sensitivity analysis was undertaken to show how the CBA findings were impacted by different assumptions.

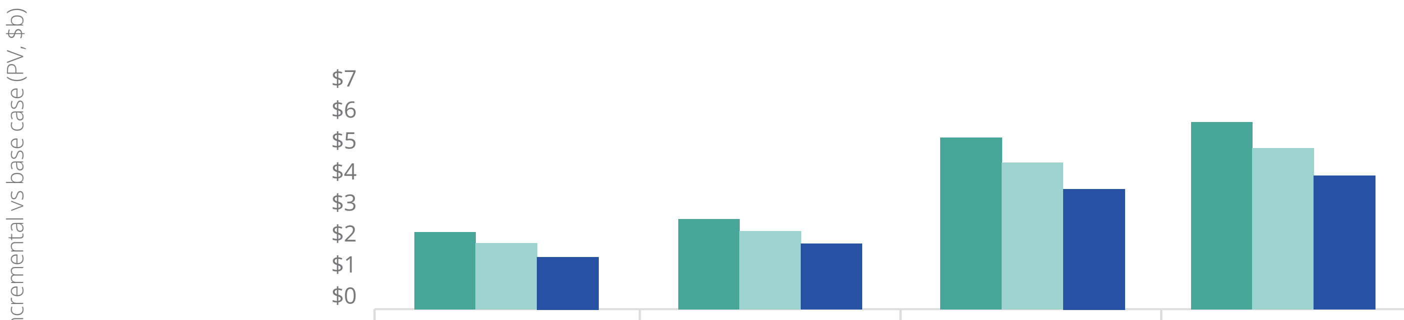
Figures 3.3 and 3.4 outline how the CBA findings are impacted by different discount rates (7% and 10%), showing that, even at higher discount rates, the benefits from the capabilities tested within the CBA remain positive across the 20-year time horizon.

Figure 3.3 Discount rate sensitivity analysis – CBA findings (AEMO ISP Step Change Scenarios 2-5)



	Scenario 2 (Simple DOE, Moderate Coverage)	Scenario 3 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 4 (Advanced DOE, High Coverage)	Scenario 5 (Advanced DOE, High Coverage with Data Hub)
Core Results (4.83% discount rate)	$1.53	$1.99	$4.69	$5.15
7%	$1.18	$1.60	$3.94	$4.35
10%	$0.84	$1.21	$3.17	$3.54

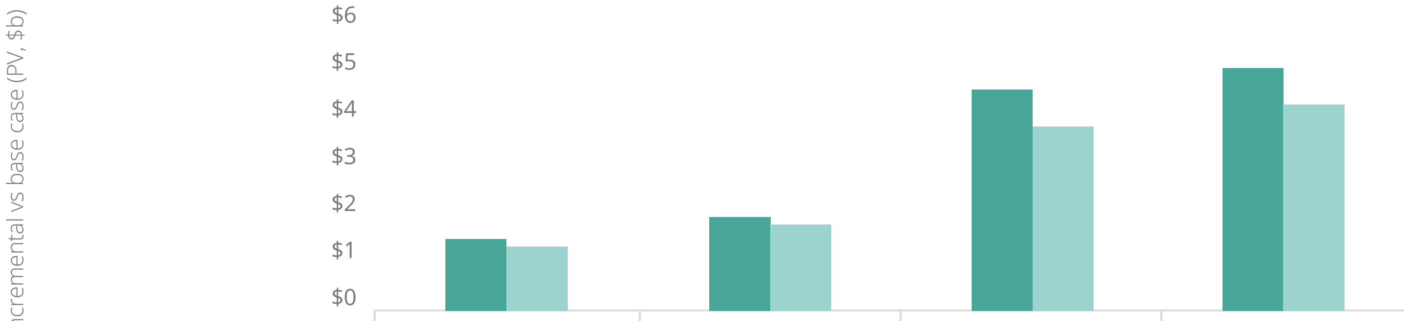
Figure 3.4 Discount rate sensitivity analysis – CBA findings (High DER Scenarios 7-10)



	Scenario 7 (Simple DOE, Moderate Coverage)	Scenario 8 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 9 (Advanced DOE, High Coverage)	Scenario 10 (Advanced DOE, High Coverage with Data Hub)
Core Results (4.83% discount rate)	$2.54	$3.00	$5.58	$6.04
7%	$2.15	$2.57	$4.80	$5.22
10%	$1.76	$2.13	$3.96	$4.33

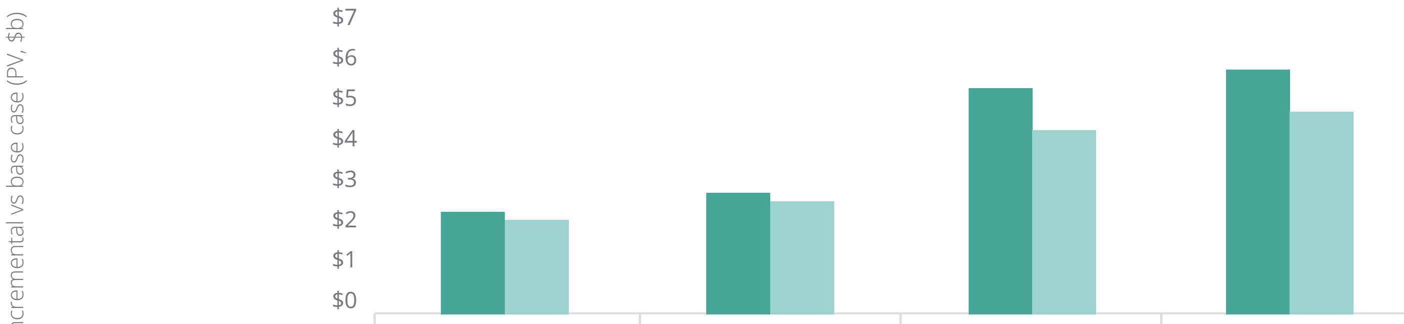
Figures 3.5 and 3.6 outline how the CBA findings are impacted by a 20% increase in costs (which may be incurred via e.g., generation build, operational and maintenance costs and distribution hosting capacity costs), showing that even with higher costs across key categories, the benefits from the capabilities tested within the CBA remain positive across the 20-year time horizon.

Figure 3.5 Cost increase sensitivity analysis (20% increase in generation build, operational and maintenance costs and distribution hosting capacity costs) – CBA findings (AEMO ISP Step Change Scenarios 2-5)



	Scenario 2 (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)
Core Results	$1.53	$1.99	$4.69	$5.15
20% cost increase across selected categories	$1.37	$1.83	$3.91	$4.37

Figure 3.6 Cost increase sensitivity analysis (20% increase in generation build, operational and maintenance costs and distribution hosting capacity costs) – CBA findings (High DER Scenarios 7-10)



	Scenario 7 (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
Core Results	$2.54	$3.00	$5.58	$6.04
20% cost increase across selected categories	$2.34	$2.80	$4.55	$5.01

3.2 Findings by market participants

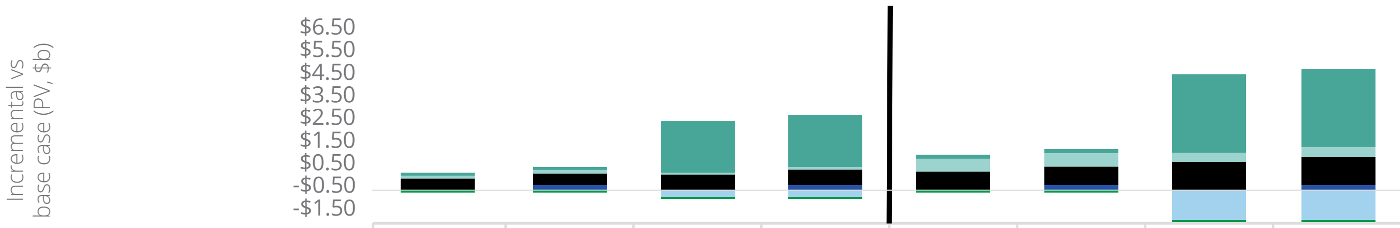
The CBA findings are presented in the section below by market participant type. Refer to Section 2.1.3 for a description of each market participant and the costs and benefits categories considered for each market participant.

3.2.1 DER Aggregators and DER Customers[59]

The categories of costs and benefits attributed to DER Aggregators and DER Customers within the CBA include:

- Avoided DER curtailment.
- DER Aggregator software platform.
- Partial displacement of large generators enabled via wholesale integration of active DER.
- Scalable DER Data Exchange (see section 3.3.1 for detail).
- LSE (see section 3.3.2 for detail).
- Visibility of DER (see section 3.3.3 for detail).

Figure 3.7 CBA findings – DER Aggregators and DER Customers (20-year time horizon, $FY23, 4.83% discount rate)



	Scenario 2 (Simple DOE, Moderate Coverage)	Scenario 3 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 4 (Advanced DOE, High Coverage)	Scenario 5 (Advanced DOE, High Coverage with Data Hub)	Scenario 7 (Simple DOE, Moderate Coverage)	Scenario 8 (Simple DOE, Moderate Coverage with Data Hub)	Scenario 9 (Advanced DOE, High Coverage)	Scenario 10 (Advanced DOE, High Coverage with Data Hub)
Partial displacement of large generators	$0.12	$0.12	$2.29	$2.29	$0.17	$0.17	$3.45	$3.45
LSE	$0.14	$0.13	$0.10	$0.10	$0.59	$0.59	$0.43	$0.42
Avoided DER Curtailment	$0.52	$0.52	$0.69	$0.69	$0.82	$0.82	$1.25	$1.25
Visibility of DER	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08	-$0.08
Data Exchange	$-	$0.23	-	$0.23	-	$0.23	$-	$0.23
DER Aggregator Platform	-$0.02	-$0.02	-$0.30	-$0.30	-$0.02	-$0.02	-$1.32	-$1.32

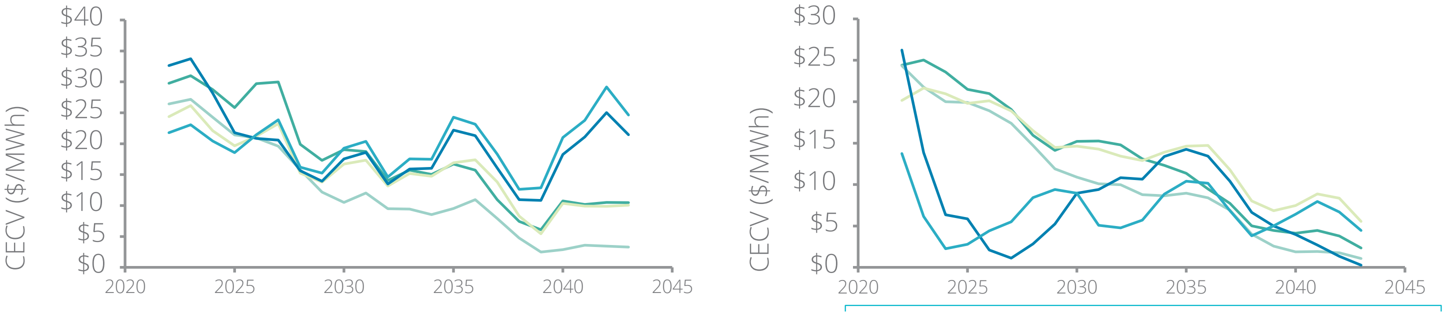
The key findings attributed to DER Aggregators and DER Customers within the CBA are detailed below.

[59] For reporting the CBA findings, DER Aggregators and DER Customers are presented together given DER Aggregators are granted permission by DER Customers to use their DER and data to deliver services according to the DER Customer preferences.

Avoided DER Curtailment

The cost of curtailment due to distribution network constraints was the total exported energy curtailed, multiplied by the CECV[60] during 9am-3pm (adapted by Energeia to represent an annualised average of 80% of peak solar generation). Therefore, it only captures solar export curtailment and not additional forms of curtailment (e.g., V2G). This is shown in Figure 3.8. The CBA found that more advanced DOE configurations can unlock greater network capacity for use by DER.

Figure 3.8 CEVC by state for Scenarios 1-5 (left) and Scenarios 6-10 (right)



DER Aggregator software platform

Table 3.1 outlines the costs to enable the DER Aggregator software platform tested within the CBA. These costs were provided by Project EDGE DER Aggregators participating in the field trial as well as other DER Aggregators operating in the NEM, outside Project EDGE.

Table 3.1 DER Aggregator software platform cost assumptions ($)

Cost Category	$
Platform development (forecasting capacity and dispatch)	$1.00m per DER Aggregator
Operational capabilities (e.g., trading desk and monitoring)	$0.37m per DER Aggregator per annum under the AEMO ISP Step Change assumptions $0.56m per DER Aggregator per annum under the High DER assumptions
IT costs	$20 per annum per customer
DOE and wholesale capabilities	$1.00m per DER Aggregator

[60] AER, 2022. Final CECV Methodology, at https://www.aer.gov.au/system/files/Final%20customer%20export%20curtailment%20value%20methodology%20-%20June%202022.pdf

Partial displacement of large generators enabled via wholesale integration of active DER

The reduction of large-scale generation costs such as in the building, operating and maintenance costs is partially driven by coordinated DER exports via VPPs and enhanced by more advanced DOEs providing greater network capacity to DER. It is therefore assumed DER Aggregators will capture value associated with this.

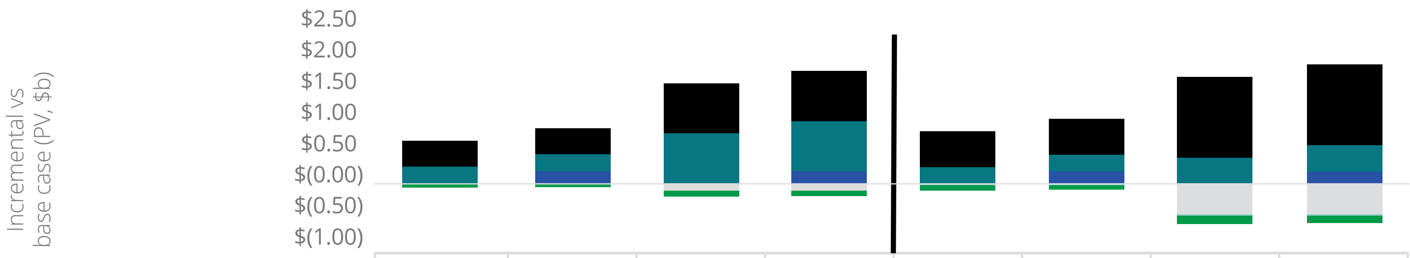
For simplicity, the CBA assumes DER Aggregators capture all the value of displacing large generators enabled via wholesale integration of active DER. In reality, DER Aggregators would likely capture a significant portion of this value.

3.2.2 DNSPs

The categories of costs and benefits attributed to DNSPs within the CBA include:

- Load hosting capacity
- Voltage hosting capacity
- Distributed Energy Resources Management System (DERMS) platform
- Scalable DER Data Exchange (see section 3.3.1 for detail)
- LSE (see section 3.3.2 for detail)[61]
- Visibility of DER (see section 3.3.3 for detail).

Figure 3.9 CBA findings – DNSPs (20-year time horizon, $FY23, 4.83% discount rate)



	Scenario 2 (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
LSE	-$0.06	-$0.05	-$0.09	-$0.08	-$0.08	-$0.07	-$0.13	-$0.12
Avoided DER Curtailment	$0.41	$0.41	$0.80	$0.80	$0.57	$0.57	$1.29	$1.29
Avoided Load Hosting Capacity Costs	$0.28	$0.28	$0.81	$0.81	$0.27	$0.27	$0.42	$0.42
Visibility of DER	$-	$-	$-	$-	-$0.02	-$0.02	-$0.02	-$0.02
Data Exchange	$-	$0.20	$-	$0.20	$-	$0.20	$-	$0.20
DERMS Platform	$-	$-	-$0.11	-$0.11	$-	$-	-$0.49	-$0.49

[61] For the purposes of the CBA the benefits associated with the LSE have been attributed to DER Aggregators, in reality it would likely offer some benefit also to DNSPs via alleviated voltage constraints.

The key findings include:

- Under the High DER uptake assumption, less expenditure is required to maintain the network as there is improved access to DER exports
- Load hosting capacity costs reduce as a result of advanced DOE configurations (e.g., maximise service DOE objective function and LV impedance model optimisation methodology) as less restrictive export arrangements reduce peak demand for some HV feeder and zone substation assets
- Voltage hosting costs reduce as a result of advanced DOE configurations (e.g., maximise service DOE objective function and LV impedance model optimisation methodology) and due to increased DOE customer coverage.

DERMS software platform

Table 3.2 outlines the costs to enable the DERMS software platform[62] tested within the CBA scenarios. These costs were provided by AusNet.

Table 3.2 DERMS software platform cost assumptions ($m)

	Daily – DOE constraint optimisation frequency **Approximation–** DOE optimisation methodology	**Intra daily –** DOE constraint optimisation frequency **LV impedance model –** DOE optimisation methodology
DERMS software platform (capex) - upfront platform development costs	Fixed $1.50m per DNSP Variable - $0.12m per integration with DER Aggregator	Fixed $4.50m per DNSP Variable - $0.36m per integration with DER Aggregator
Annual DERMS software platform (opex) - platform operation and integration	Fixed $0.14m per DNSP per annum Variable - $0.045m per 10,000 customers	Fixed $0.45m per DNSP per annum Variable - $0.13m per 10,000 customers
Cost of complying with laws, regulations, and administration (opex)	Fixed $0.63m per DNSP Variable - $0.045m per 50,000 customers	Fixed $0.63m per DNSP Variable - $0.045m per 50,000 customers

[62] Software platform used by DNSPs for the coordination and management of DER.

3.2.3 TNSPs

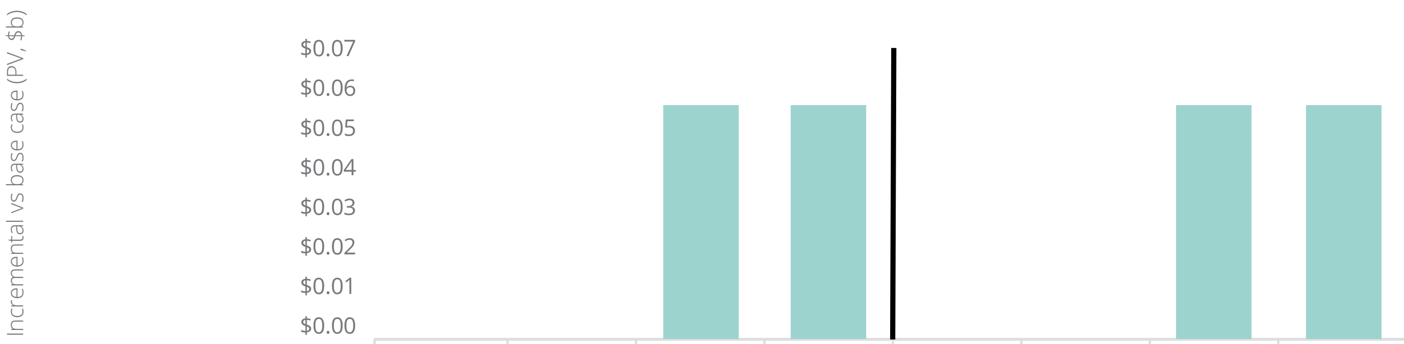
The categories of costs and benefits attributed to TNSPs within the CBA include:

- load hosting capacity[63].

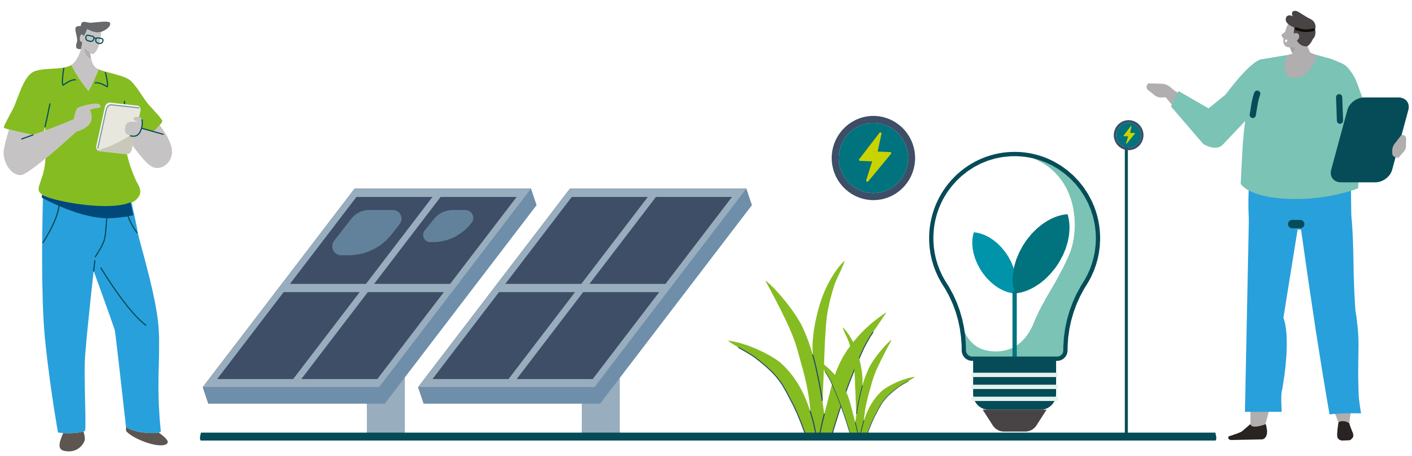
The key findings include:

- Increasing DOE customer coverage and implementing an LV impedance model optimisation methodology reduces costs for TNSPs by unlocking more DER exports, reducing throughput of energy within the transmission network.

Figure 3.10 CBA findings – TNSPs (20-year time horizon, $FY23, 4.83% discount rate)



	Scenario 2 (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
Load Hosting Capacity	$-	$-	$0.06	$0.06	$-	$-	$0.06	$0.06



[63] TNSP voltage hosting capacity costs were not considered in the CBA as DOEs primarily operate to stabilise voltage at the distribution level.

3.2.4 Market Operator

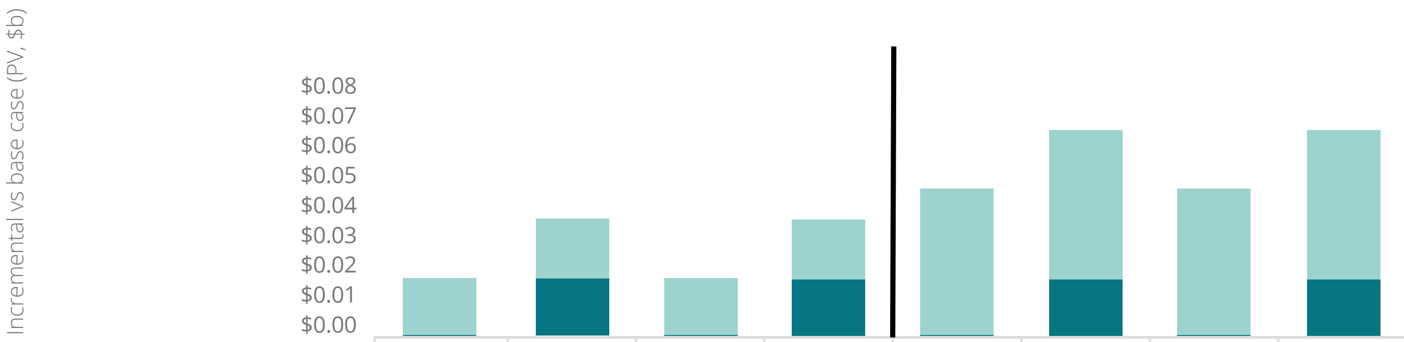
The categories of costs and benefits attributed to the Market Operator within the CBA include:

- Scalable DER Data Exchange (see section 3.3.1 for detail).
- LSE application costs under a centralised data hub approach (see section 3.3.2 for detail).
- Visibility of DER (see section 3.3.3 for detail).

The key findings relating to the Market Operator include:

- The use of a data hub reduces the number of integrations for the Market Operator compared to a point-to-point approach.
- Increased visibility of DER can ensure more accurate demand forecasts (via better situational awareness and increased certainty), reducing the frequency and severity of power system events that result in[64]:
  - the procurement of Reliability and Emergency Reserve Trader (RERT)[65].
  - load shedding[66] and region black outs.

Figure 3.11 CBA findings – Market Operator (20-year time horizon, $FY23, 4.83% discount rate)



	Scenario 2 (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
LSE		-$0.002		$0.002		-$0.002		-$0.002
Visibility of DER	$0.02	$0.02	$0.02	$0.02	$0.05	$0.05	$0.05	$0.05
Data Exchange	$-	$0.02	$-	$0.02	$-	$0.02	$-	$0.02

[64] The majority of benefits as a result of greater visibility for the Market Operator and therefore greater demand forecasts (via better situational awareness and increased certainty) are captured within 'DNSP' and 'Other'.

[65] AEMO, at https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert#:~:text=The%20Reliability%20and%20Emergency%20Reserve,system%20security%20using%20reserve%20contracts

[66] AEMO, at https://aemo.com.au/en/learn/energy-explained/energy-101/explaining-load-shedding#:~:text=Load%20shedding%20is%20the%20deliberate,and%20the%20supply%2Ddemand%20balance

3.2.5 Other

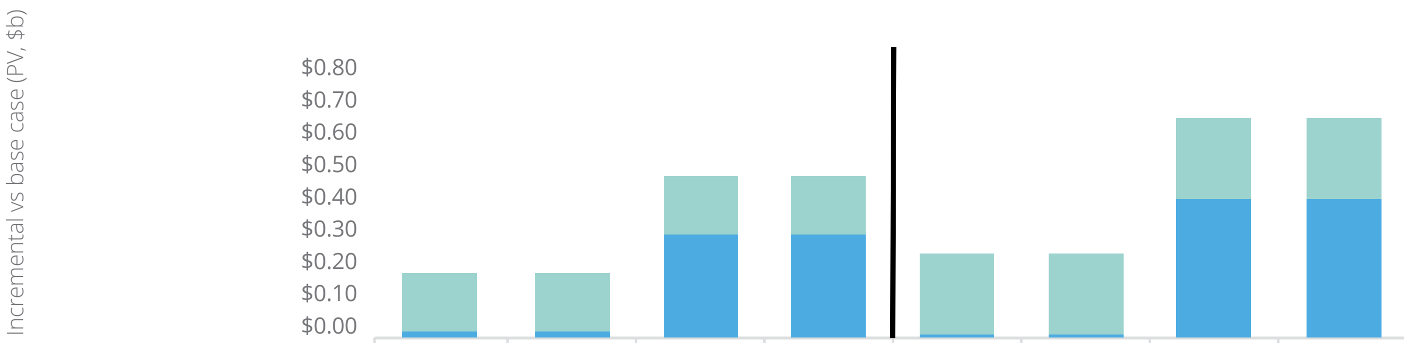
Based on current market arrangements the costs and benefits identified in sections 3.2.1 to 3.2.5 are expected to flow through to all consumers. This section considers other categories of costs and benefits that relate to broader 'whole of system' impacts, which apply to many different participants and are not clearly traceable to a specific market participant, including:

- FCAS total cost (contingency and regulation – assuming that DER Aggregators only participate in contingency FCAS markets).
- Visibility of DER (see section 3.3.3 for detail).
- Electricity sector emissions (CO2e)[67].

The key additional findings include:

- Greater export capacity (due to more advanced DOEs) of DER participating in VPPs reduces the cost of meeting FCAS requirements
- The Demand Response Mechanism and Ancillary Services unbundling rule change[68], which commenced in 2017, has enabled participation of VPP in FCAS markets. The proportion of FCAS costs attributed to each market participant is not included in the CBA, given the shift of such costs between market participants across the 20-year time horizon represents a transfer between market participants.

Figure 3.12 CBA findings – Other (20-year time horizon, $FY23, 4.83% discount rate)



	Scenario 2 (Simple DOE, Moderate Coverage)	**Scenario 3** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 4** (Advanced DOE, High Coverage)	**Scenario 5** (Advanced DOE, High Coverage with Data Hub)	**Scenario 7** (Simple DOE, Moderate Coverage)	**Scenario 8** (Simple DOE, Moderate Coverage with Data Hub)	**Scenario 9** (Advanced DOE, High Coverage)	**Scenario 10** (Advanced DOE, High Coverage with Data Hub)
Visibility of DER	$0.18	$0.18	$0.18	$0.18	$0.25	$0.25	$0.25	$0.25
FCAS	$0.02	$0.02	$0.32	$0.32	$0.01	$0.01	$0.43	$0.43

[67] Recognising the uncertainty associated with social cost of carbon values in Australia these findings have been presented standalone (not included) to the CBA findings presented in section 3.1.

[68] AEMC, Demand Response Mechanism and Ancillary Services Unbundling, at https://www.aemc.gov.au/rule-changes/demand-response-mechanism

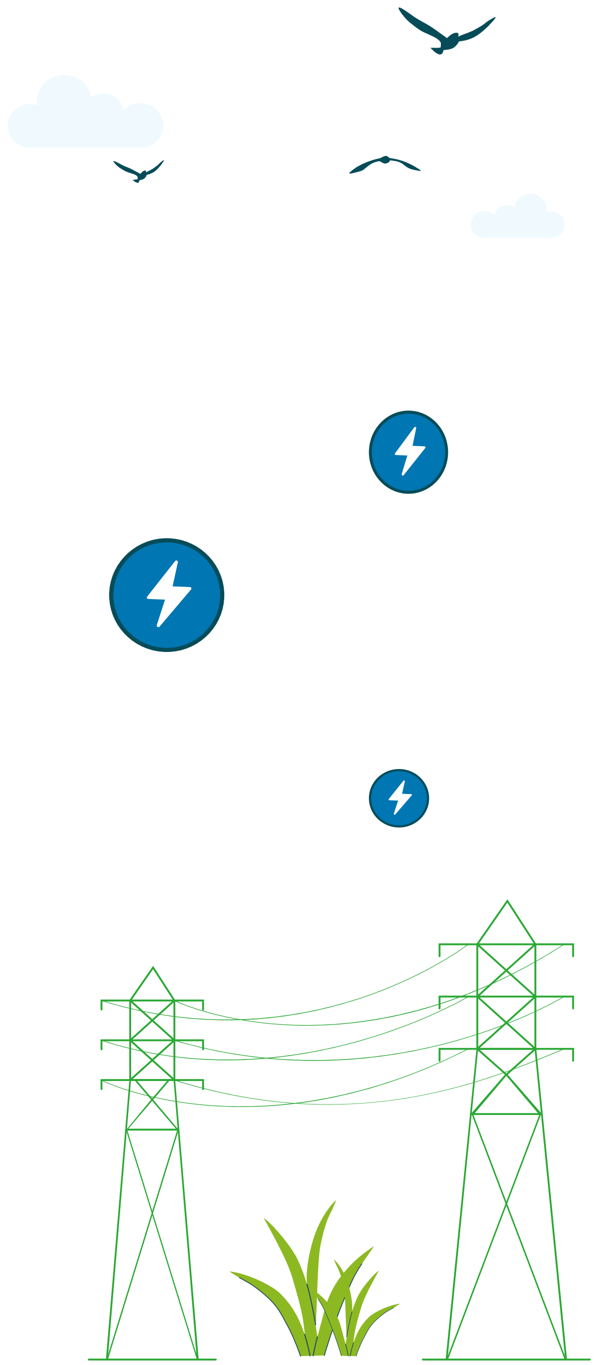
Emissions (tCO2e)

The CBA modelled the emissions (tCO2e)[69] associated with electricity generation per CBA scenario.

Emissions reduction is driven by DER displacing fossil fuel generators. This is enabled primarily by greater DOE customer coverage that allows for more network capacity to be unlocked and utilised by DER and VPPs.

A social cost of carbon[70] was applied to value the avoided emissions (tCO2e).[71] In FY23 (CBA base year) the assumed social cost of carbon is ~$101 (per tCO2e) and in FY42 the assumed social cost of carbon is ~$147 (per tCO2e).

The CBA found that across the 20-year time horizon total emissions avoided can be up to 18,859,157 tCO2e ($1.54b)[72] under the AEMO ISP Step Change DER uptake assumptions and up to 32,871,522 tCO2e ($2.60b)[73] under the High DER uptake assumptions.



[69] CO2e is a measure used to compare the emissions from various greenhouse gases based on their global-warming potential, by converting amounts of other gases to the equivalent amount of carbon dioxide with the same global warming potential.

[70] A social cost of carbon when performing a CBA to encompass a societal welfare point of view.

[71] Environmental Protection Agency (2017), The Social Cost of Carbon.

[72] Scenario 5 - Advanced DOE, High Coverage with Data Hub (AEMO ISP Step Change).

[73] Scenario 10 - Advanced DOE, High Coverage with Data Hub (High DER).

3.3 Additional findings by key capabilities

This section includes additional detail on the findings of key capabilities within the CBA.

3.3.1 Scalable DER Data Exchange

As noted in section 2.2.4 the CBA considered three scalable DER data exchange approaches

- Point-to-point – closest to the current arrangement in the market, where integration occurs between each participant in the facilitation of DER use cases and services
- Centralised data hub – each participant only needs to integrate with a common industry data hub once, with data exchanged via a central broker (assumed to be AEMO in Project EDGE)
- Decentralised data hub - each participant only needs to integrate with a common industry data hub once, with data exchanged between participants in a way that does not rely on a single central broker.

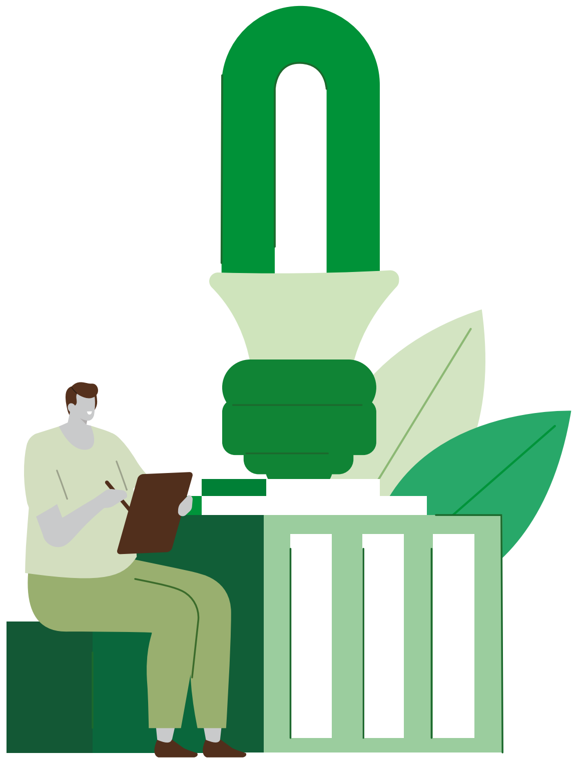
Overall, the CBA found either data hub model can provide a lower cost approach for scalable DER data exchange between participants compared with the point-to-point approach.

The CBA found that across the 20-year time horizon[74], a centralised data hub reduces costs by up to $0.44b and a decentralised data hub reduces costs by up to $0.45b compared to a point-to point approach.

Both data hub options reduce costs: each participant only needs to integrate with the data hub once in order to interact with other participants, which reduces the number of integrations.

In addition, a data hub as compared to a point-to point approach could deliver further upside through facilitating new DER-based service innovations more easily and at lower cost as it simplifies integration, identity verification and reporting between participants.

Table 3.3, 3.4 and 3.5 show the costs associated with the three scalable DER data exchange approaches for the Market Operator, DNSPs and DER Aggregators.



[74] Assuming 13 DNSPs by FY42 each integrating with on average 27 DER Aggregators/Retailers/OEMs and assuming 52 DER Aggregators/Retailers/OEMs by FY42 each integrating with on average 6 DNSPs.

Market Operator

Table 3.3 Market Operator costs across scalable DER data exchange approaches (20-year time horizon, $FY23, 4.83% discount rate)

Cost Category	Point-to-Point	Centralised Hub[75]	Decentralised Hub
Initial Infrastructure Build	$3.1m	$16.3m[75]	$4.8m (total cost that is shared across a number of supporting parties)
Integration Costs (including DERMS costs)	$3.5m	$0.4m	$0.4m
Identity and Access Management (IAM)	$13.7m	$13.7m	$13.7m (total cost that is shared across a number of supporting parties)
Data Storage (e.g., DER Register)	$1.1m	$1.1m	$1.1m
Project Management Costs (FTEs)	$22.1m	$5.1m	$3.7m
Hosting and Licence Fees	Included in project management costs	Included in project management and infrastructure build costs	Included in project management costs
Support Services	Included in project management and infrastructure build costs		
Total	**$43.6m**	**$36.4m**	**$23.4m**

[75] Based on augmenting the existing e-hub to perform additional daily and intra-day DER use cases.

DNSPs

Table 3.4 DNSPs costs across scalable DER data exchange approaches (20-year time horizon, $FY23, 4.83% discount rate)[76]

Cost Category	Point-to-Point	Centralised Hub	Decentralised Hub
Initial Infrastructure Build	N/A – DERMS software platform costs captured separately and assumed to be leveraged (see section 3.2.2).		
Integration Costs	$125.3m	$2.3m	$2.3m
Identity and Access Management (IAM)	Included in the integration costs above	Included in the integration costs above	Included in the integration costs above
Data Storage (e.g., DER Register)	$27.5m	$27.5m	$27.5m
Project Management Costs (FTEs)	$90.4m	$13.2m	$13.2m
Hosting and Licence Fees	Included in the integration costs and storage costs above	Not Applicable	Not Applicable
Support Services	Included in the integration costs and storage costs above	Not Applicable	Not Applicable
Total	**$243.2m**	**$43.1m**	**$43.1m**

DER Aggregator

Table 3.5 DER Aggregator costs across scalable DER data exchange approaches (20-year time horizon, $FY23, 4.83% discount rate)[77]

Cost Category	Point-to-Point	Centralised Hub	Decentralised Hub
Initial Infrastructure Build	N/A – DER Aggregator software platform costs captured separately and assumed to be leveraged (see section 3.2.1).		
Integration Costs	$180.6m	$16.1m	$16.1m
Identity and Access Management (IAM)	Included in the integration costs above	Included in the integration costs above	Included in the integration costs above
Data Storage (e.g., DER Register)	$12.5m	$12.5m	$12.5m
Project Management Costs (FTEs)	$76.8m	$10.0m	$10.0m
Hosting and Licence Fees	Not Applicable	Not Applicable	Not Applicable
Support Services	Not Applicable	Not Applicable	Not Applicable
Total	**$269.8m**	**$38.5m**	**$38.5m**

[76] Assuming 13 DNSPs by FY42 each integrating with on average 27 DER Aggregators/Retailers/OEMs.
[77] Assuming 52 DER Aggregators/Retailers/OEMs by FY42 each integrating with on average 6 DNSPs.

3.3.2 LSE

The CBA found that across the 20-year time horizon[78] the implementation of an LSE (with data exchange via a data hub) can result in an incremental benefit of up to $0.08b[79] under the AEMO ISP Step Change assumptions and up to $0.51[80] under the High DER uptake assumptions based only on the use of an LSE to reduce DER export curtailment.

The establishment of an LSE to facilitate scalable and competitive trade of standardised DER-based network support services is intended to enable DER Aggregators to offer and deliver network support services at a lower cost. In Project EDGE, DER Aggregators utilise the same fleet of DER to offer and deliver wholesale and network support services.

The CBA found that the costs to implement an LSE via a data hub arrangement, as compared to the alternative point-to-point arrangement, would be $9m lower. This is due to the reduced number of integrations required, as each participant would integrate with the data hub once.

Table 3.6 outlines the costs associated with the key components required to operate an LSE. These costs were provided by Project EDGE participants based on actual costs incurred in establishing and maintaining the Project EDGE field trial LSE arrangements.

Table 3.6 Costs associated with each of the key activities in establishing and maintaining an LSE

Cost Category	Relevant market participant	$
Establishing LSE capabilities including integration (initial costs)	DNSPs	$0.75m per DNSP
Managing LSE capabilities (ongoing costs)	DNSPs	$0.35m per DNSP per annum
DERMS software platform – LSE component[81]	DNSPs	Fixed $1.09m per DNSP Variable - $0.08m per integration with DER Aggregator Variable - $0.005m per 10,000 customers
Establishing LSE capabilities including integration (initial costs)	DER Aggregators	$0.075m per DER Aggregator

[78] The CBA assumes for the purposes of assessing the LSE that there will be 13 DNSPs by FY42 each integrating with on average 22 DER Aggregators/Retailers/OEMs and assumes that there will be 52 DER Aggregators/Retailers/OEMs by FY42 each integrating with on average 4 DNSPs.

[79] Scenario 3 - Simple DOE, Moderate Coverage with Data Hub (AEMO ISP Step Change).

[80] Scenario 8 - Simple DOE, Moderate Coverage with Data Hub (High DER).

[81] 3x uplift under an intra daily DOE constraint optimisation frequency and LV impedance model DOE optimisation methodology.

Table 3.6 continued Costs associated with each of the key activities in establishing and maintaining an LSE

Managing LSE capabilities such as trading desk and monitoring (ongoing costs)	DER Aggregators	$0.12m per annum under the AEMO ISP Step Change assumptions $0.18m per annum under the High DER assumptions
LSE Demand[82] (e.g., modelling for service valuation and definition, registration, identity management and portfolio management systems and processes)	DER Aggregators	$0.43m per DER Aggregator per annum
LSE Voltage (e.g., modelling for service valuation and definition, registration, identity management and portfolio management systems and processes)	DER Aggregators	$0.55m per DER Aggregator per annum
Establishing the LSE Application on the Data Hub.	Marker Operator under a Centralised Hub Shared across a number of supporting parties under a Decentralised Hub	$3.00m[83]

[82] Costs based on an average of high and low levels of firmness of services.

[83] Establishing LSE capabilities under a point-to-point approach include DNSP and DER Aggregator costs for each bi-lateral integration.

The Project EDGE field trial demonstrated, from a technical perspective, that aggregated DER can be used to deliver demand management and voltage management services.

The assessment of value from an LSE was informed by the University of Melbourne (UoM) research paper, which noted that the value of network support services is directly linked to its ability to relive network constraints which are locational and temporal[84]. The CBA has adopted a conservative approach to valuing the benefits of an LSE, based only on its use to reduce DER export curtailment. Based on insufficient data the potential benefits related to the use of an LSE to maintain reliability and quality of electricity supply in the distribution system these benefits were not quantified.

To simplify the process of assigning a value to the use of an LSE to reduce DER export curtailment[85], the CBA has used the 2022 CECV, published by the AER[86], to derive an average price associated with reduced curtailment[87]. This price was applied to the CBA's forecast annual volume of curtailed exports[88].

These findings indicate value in an LSE. However, this calculated value only represents a portion of the potential applications of an LSE. A more complete representation of its value would require additional modelling of market scenarios that considers localised factors such as network configurations, constraints, number and location of residents and customer behaviour in addition to local DER penetration levels. Network operation choices, such as how DNSPs use transformer settings to increase voltage head room would also need to be considered.

3.3.3 Visibility of DER

The CBA found that the defined uplift in visibility of DER can result in an incremental benefit of up to $0.12b[89] under the AEMO ISP Step Change assumptions and up to $0.20b[90] under the High DER assumptions (assuming Flex bidding).

As noted in section 2.2.4, the CBA focused on the incremental shift from a defined current state (i.e., before Scheduled Lite and SCADA Lite implementation) where there is visibility of DER based only on:

- DER participating in the WDR mechanism[91]
- The demand side participation information portal, and
- The DER Register

to a future state where DER is fully scheduled ('visibility with controllability') and aligned with appropriate technical and performance standards.

The CBA found more accurate demand forecasts are possible via greater visibility of DER, reducing the need for the procurement of RERT, risk of load shedding or of a system black event in the most extreme circumstances. In addition, it can ensure more efficient dispatch at periods of peak demand (this is critical given distribution network augmentation is largely based on managing peak demand).

Additional detail on the findings for visibility of DER be found in Appendix B.

84 S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).

85 UoM analysis suggests that reactive power services from DER can be applied to relieve export constraints in the low voltage network as exports are typically limited by voltage limits rather than the thermal ratings of network assets. Refer to S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).

86 AER, 2022. Final CECV Methodology, at https://www.aer.gov.au/system/files/Final%20customer%20export%20curtailment%20value%20methodology%20-%20June%202022.pdf

87 The calculation is based on using a CECV average value across the NEM over the 20-year CBA time horizon of $48.38/MWh.

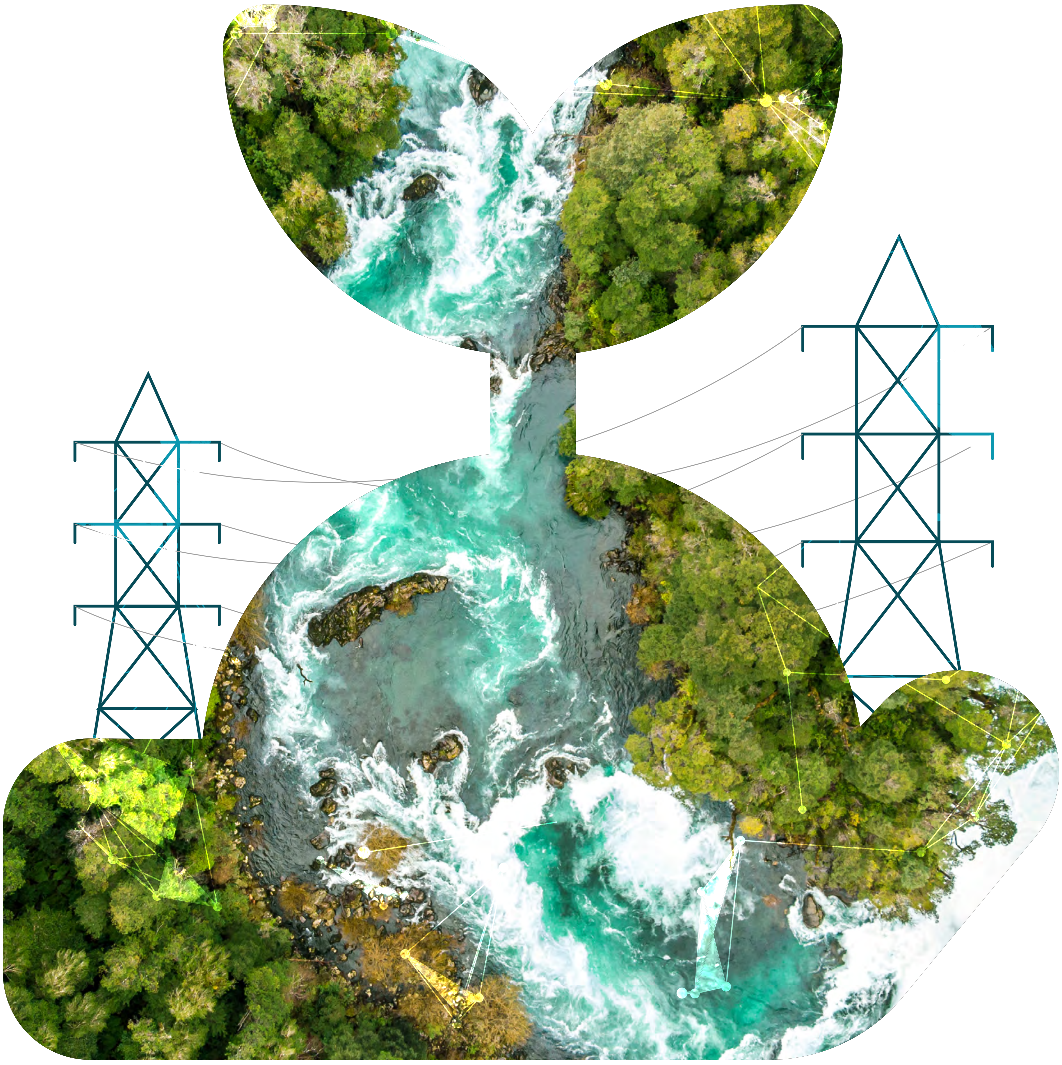
88 Based on the Energeia TEM outputs for potential avoided voltage constraint curtailment (post DOE configurations tested within the CBA scenarios) over the 20-year CBA time horizon.

89 Scenario 5 - Advanced DOE, High Coverage with Data Hub (AEMO ISP Step Change assumptions).

90 Scenario 10 - Advanced DOE, High Coverage with Data Hub (High DER assumptions).

91 The WDR mechanism allows demand side (or consumer) participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. The WDRM has a range of eligibility requirements including customer load size.

4
Roles and Responsibilities



CBA Findings

The Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA.

Understanding the value of integrating DER into the NEM requires examination within the CBA of the roles of market participants and the responsibilities assigned to those roles.

Project EDGE sought to examine, as per its Research Plan[92], the roles and responsibilities of market participants within the bounds of the Open Energy Networks Project (OpEN) Hybrid Model[93]. This included the extent to which these roles and responsibilities deliver on the NEO and align with current roles under the existing regulatory frameworks.

From 2018 to 2020, AEMO and Energy Networks Australia (ENA) undertook OpEN[94] to explore different market frameworks to cost-effectively integrate DER into the NEM.

OpEN proposed the Hybrid Model as the most suitable framework for integrating DER. It also proposed that trials should be conducted to understand how a Hybrid Model could best integrate DER. Accordingly, as arrangements of roles in a market drive value, the Project EDGE roles and responsibilities along with some alternatives within the Hybrid Model Framework were assessed in the CBA.

In addition to the findings gathered through the Project EDGE field trial, the roles and responsibilities under the Hybrid Model were also assessed within Project EDGE via:

- the CBA scenarios.
- using multi-criteria analysis (MCA).

The methodology is discussed in this section rather than Section 2 for ease of reader understanding. The process for methodology development and analysis of roles and responsibilities followed the steps below:

Step A – Determine functions from OpEN and the means for inclusion in the CBA.

Step B – Define MCA Criteria.

Step C – Assess the Project EDGE arrangement and the selected alternative arrangements of roles and responsibilities.

[92] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

[93] AEMO and Energy Networks Australia (2019), at http://www.energynetworks.com.au/assets/uploads/open_energy_networks_-_required_capabilities_and_recommended_actions_report_22_july_2019.pdf

[94] Ibid.

Step A – Determine functions from OpEN and the means for inclusion in the CBA

OpEN used the functions listed in Table 4.1 to define each of the frameworks assessed[95] (e.g., Hybrid, Single Integration Platform, Two Step Tiered Platform and Independent DSO framework). Therefore, these functions represent a logical point from which to assess arrangements of roles and responsibilities within the Hybrid Model.

Table 4.1 also outlines the Project EDGE description of each function (i.e., how it was implemented in the Project EDGE field trial), and the means for inclusion in the CBA (i.e., via CBA scenarios or MCA).

Table 4.1 Functions from OpEN and the means for inclusion in the CBA

OpEN Function	OpEN High Level Description	Project EDGE Implementation Description	Inclusion in CBA
1. Distribution system monitoring and planning	To inform distribution network constraint development.	DSOs engage with various market participants for the development and operation of the distribution network and gather data for active network management.	No • Lack of feasible alternatives within the Hybrid Model identified for inclusion in MCA.
2. Distribution constraints development	To develop distribution network constraints in the form of long-term operating envelopes that will be a key input into the distribution level optimisation.	DSOs undertake the following: • Calculating distribution constraints and long-term requirements for distribution network support. • Communicating DOEs. • Pre-qualification for LSE requirements and operational assessment of LSE need. • Publishing service needs and requirements via an LSE for DER Aggregators.	Yes – CBA Scenarios • Communicating DOEs directly point-to-point compared with via a data hub. • Engaging DER via an LSE directly point-to-point compared with via a data hub.

[95] EA Technology (July 2019), at http://www.energynetworks.com.au/resources/reports/ea-technology-open-energy-networks-project/

Table 4.1 continued Functions from OpEN and the means for inclusion in the CBA

3. Forecasting systems	Provide key forecasting information to allow for distribution level optimisation.	DER Aggregators gather all the forecast data such as weather forecast, current metering data, operational impacts and customer data profiles.	No • Lack of feasible alternatives within the Hybrid Model identified for inclusion in MCA.
4. Aggregator DER bid and dispatch	Aggregates local DER installation to provide bids into the markets (within provided operating envelopes).	Engaging with DER to create DER Aggregator portfolios: • Engage with prospective customer and exchange customer information. • Create customer offer. • Customer enrolment. • Service contract. DER Aggregator market engagement: • Applying for participation in wholesale energy (enrolment process). • Forecasting of price responsive DER capacity. • Forecasting of uncontrolled load. • Submit portfolio-wide bi-directional market offers for wholesale energy within DOE (acts as a forecast). • Market Operator: DER portfolio-level dispatch instruction sent for wholesale energy. • Dispatch individual DER devices in response to dispatch instructions. • DSO: LSE service trigger communicated to DER Aggregators.	No Lack of feasible alternatives within the Hybrid Model identified for inclusion in MCA.

Table 4.1 continued Functions from OpEN and the means for inclusion in the CBA

5. Retailer DER bid and dispatch	Retailers engage with DER resources to develop portfolios of DER customers (and services) and engage with network operators and markets to submit bids and offers.	In Project EDGE Retailers can be DER Aggregators; the same capabilities apply.	No • In Project EDGE Retailers can be DER Aggregators; the same capabilities apply.
6. DER optimisation at the distribution network level	Optimise operating envelopes to ensure aggregated bid stacks for DER per service area can feed into wholesale optimisation taking account of distribution network constraints.	• Rules or guidelines created to develop customer DOEs. • DSOs: Calculate and communicate DOEs. • Market Operator: Publish DOEs to DER Aggregator. • DER Aggregators: Aggregation of wholesale bids. • DER Aggregators: Co-optimisation of LSE bids by including quantity within portfolio-wide wholesale bid to AEMO (Function 4), within DOEs.	Yes – CBA MCA.
7. Wholesale – distributed optimisation	Integrate distribution level optimisation results into existing wholesale market optimisation.	Optimisation of constrained wholesale portfolio level bids in NEM central dispatch process.	No • Lack of feasible alternatives within the Hybrid Model identified for inclusion in MCA.
8. Distribution network services	Distribution network services, such as power quality/voltage control, which can be provided by aggregated DER.	DSO contracts with DER Aggregators via the LSE to provide local network support services.	No • Lack of feasible alternatives within the Hybrid Model identified for inclusion in MCA.

Table 4.1 continued Functions from OpEN and the means for inclusion in the CBA

9. Data and Settlement (network services	Settlement of network support and control ancillary services at distribution and transmission level.	• DER Aggregators: Transmit DER service delivery verification data for use in LSE settlement. • DSOs: Settlements for LSE - following verification of service via telemetry data and the associated payment or clawback which is communicated through a data hub.	Yes – CBA MCA.
10. Data and settlement (wholesale, RERT, FCAS and SRAS)	AEMO settles wholesale, FCAS and SRAS transactions at distribution and transmission level.	• DER Aggregators: Transmit telemetry or other non-smart meter service delivery verification data for use in wholesale settlement. • Market Operator: Settlement of wholesale energy using smart meter data and portfolio level telemetry as required.	No • Outside CBA scope.
11. DER Register	AEMO to provide DER register based on AEMC rule requirements. Periodically gather up-to-date DER information from market participants. Share disaggregated data and publish aggregated locational and technical data of DER with relevant market participants.	• DSOs: Send DER information from connection agreement. • Facilitating data exchange for DER use cases (e.g. DOEs, DER Aggregator bids, telemetry, dispatch instructions and LSE). • Establish, maintain and provide access to DER register.	Yes – CBA Scenarios • Utilising a centralised data hub with a single broker to record and share DER data among relevant participants. • Utilising a decentralised data hub shared among participants to record and share DER data among relevant market participants.

Table 4.1 continued Functions from OpEN and the means for inclusion in the CBA

12. Connecting DER	Regulatory, technical and commercial arrangements around the connection of DER to the distribution network.	• DSOs monitoring compliance and enforcing compliance with wholesale dispatch and DOEs • DSOs monitoring compliance with LSE services to determine service delivery.	Yes – CBA MCA • Specifically, DOE compliance monitoring and DOE compliance enforcement were identified as activities that have feasible alternative arrangements within the Hybrid Model.
13. Network and System Security with DER	DER contribution to, and influence on, system security.	Constraint net/gross output at site to zero via DOEs and market directions (Market Operator).	No • Outside CBA scope.

Step B – Define MCA Criteria

MCA is an analysis process that scores and rates options against multiple criteria. MCA provides a way of analysing alternatives against outcomes that are important to decision-makers, but which cannot be readily quantified and monetised[96][97].

Table 4.2 describes the criteria and weightings applied to the OpEN functions tested in the MCA, which was developed in alignment with the NEO.

[96] Commissioner for Better Regulation (2014), Guidance Note: Multi-Criteria Analysis, Department of Treasury and Finance, Melbourne.

[97] MCA was selected to assess alternative arrangements of roles and responsibilities within the Hybrid Framework that were not able to be quantified in the CBA. This was because the Project EDGE timeline and budget did not allow for parallel marketplaces with different arrangements of roles and responsibilities to be tested in the field trial.

Table 4.2 MCA Criteria

Criteria	Weightings	Key Question	Criteria sub questions
Delivers value to consumers	35%	Does the arrangement encourage competition between parties that promote the long-term interests of consumers (e.g., lower costs and pricing, innovation, quality services and more consumer choice)?	• Does the arrangement of roles and responsibilities encourage competition in favour of the consumer? • To what extent does the arrangement for roles and responsibilities improve consumer value?
Efficiency	20%	Does the arrangement encourage efficient investment, operation, and use of electricity services?	• Is the efficiency of investment, operation and use of electricity services enhanced under the arrangement of role.
Adaptability	20%	Is the arrangement responsive and adaptable to market changes over time (e.g., shifts in accountability in response to changes in DER penetration and market participation)?	• How flexible is the arrangement for roles and responsibilities and is it designed with a long-term outlook (i.e., room to adapt to different market eventualities)? • Is responsiveness to market changes improved under the arrangement for roles and responsibilities?
Opportunities and incentives	15%	What are the opportunities, market signals and commercial incentives for businesses and do they align with the long-term interests of consumers?	• To what extent are commercial incentives aligned with consumer interests? • Do market signals provide an improvement in accurate information for the responsive parties?
Allocation of risk	10%	Does the arrangement allocate risks and accountabilities to the parties who are in the best position to manage them and are they incentivised to do so?	• Is risk and accountability assignment improved by the role and responsibility arrangement? • What incentives are in place for parties to manage the risks and accountabilities and do they minimise risk (including cyber security risks)?

Table 4.3 describes the MCA scale used to rate the degree to which each arrangement of roles and responsibilities fulfils the criteria.

Table 4.3 MCA rating scale

Rating	Very Weak	Weak	Moderate	Strong	Very Strong
Rating symbol	○	◔	◑	◕	●

Step C – Assess the Project EDGE arrangement and the selected alternative arrangements of roles and responsibilities

As outlined in Table 4.1, the following functions – and the assessment of roles and responsibilities against these functions – were tested in the CBA scenarios: Function 2: Distribution Constraints Development; and Function 11: DER Register.

As outlined in section 3.3, the CBA found that utilising a data hub approach to scalable DER data exchange (including for communicating DOEs) can provide a lower cost approach than one with many point-to-point interactions. Additionally, the data hub can facilitate improved access to additional DER based service innovations (such as an LSE or other B2B services) going forward, given it simplifies integration, identity verification and reporting between participants compared to a point-to point approach.

The CBA found no significant difference in costs between centralised and decentralised data hubs in terms of recording and sharing DER data among relevant participants. However, the decentralised hub facilitates a shared governance and ownership model with the aim of increasing opportunities for participants to innovate and deliver services to DER customers.

The remaining functions considered within the CBA were tested in the MCA (see table 4.4 below): Function 6: DER optimisation at the distribution network level; Function 9: Data and Settlement; and Function 12: Connecting DER[98].

As in the Project EDGE arrangement, the alternative arrangements of roles and responsibilities considered were determined based on the principle that creating new or duplicating existing roles and responsibilities is less efficient than extending current ones.

[98] DOE compliance monitoring and DOE compliance enforcement were separately assessed under the function of connecting DER (#12) in the MCA.

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Table 4.4 MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score		Alterative Arrangements	Criteria and Score		Explanation
DER optimisation at the distribution network level (#6)	6a) The Project EDGE arrangement involves DER Aggregators receiving all external signals (prices and constraints) and optimising DER portfolios on behalf DER Customers (including the co-optimisation of local network support services bids against wholesale opportunities).	Delivers value to consumers	◕	6b) The DNSP offers a price for DER Aggregators to accept a reduced or alternative DOEs to alleviate forecast distribution network constraints. The DER Aggregator is paid for this reduced or alternative DOE then constructs bids that are within new adjusted DOEs.	Delivers value to consumers	◑	Alternative arrangement could limit DER Aggregators ability to utilise their portfolio to smooth out real time operational volatility across individual sites by requiring capacity to be provided by specific NMIs
		Efficiency	◕		Efficiency	◕	Minimal variance between arrangements – however the Project EDGE arrangement does have slightly more complexity in terms of bidding through an LSE for local network services, compared with receiving payments for lower DOEs during time of network congestion
		Adaptability	◕		Adaptability	◕	Minimal variance between arrangements
		Opportunities and incentives	◕		Opportunities and incentives	◕	
		Allocation of risk	◕		Allocation of risk	◕	
		Overall	◕		Overall	◕	Minimal variance between arrangements

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Table 4.4 continued MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score	Alterative Arrangements	Criteria and Score	Explanation
DER optimisation at the distribution network level (#6)			6c) DER Aggregator submits a NMI level bi-directional offer for each site to the DNSP. DNSP calculates DOE capacity among sites favouring those cheaper. DER Aggregator submits NMI level bids to AEMO for dispatch. AEMO calculates NMI level dispatch instructions using a bid stack.	Delivers value to consumers	Alternative arrangement could limit a DER Aggregator's ability to utilise their portfolio to smooth out real time operational volatility across individual sites, by requiring capacity to be provided by specific NMIs
				Efficiency	Alternative arrangement likely to be more costly for DER Aggregators which could impact scalability
				Adaptability	Alternative arrangement likely to be more costly for DER Aggregators which could impact adaptability
				Opportunities and incentives	Minimal variance between arrangements
				Allocation of risk	
				Overall	Overall, the Project EDGE arrangement is less complex and therefore more likely to scale and be adaptable to future changes

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Table 4.4 continued MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score	Alterative Arrangements	Criteria and Score		Explanation
DER optimisation at the distribution network level (#6)			6d) AEMO receives and co-optimises between wholesale energy, FCAS and local network services. Three separate self-constrained bids are supplied by the DER Aggregator.	Delivers value to consumers	◑	Alternative arrangement would be computationally costly for AEMO and complex for DER Aggregators in needing to submit 3 different bid files
				Efficiency	◑	
				Adaptability	◑	Alterative arrangement likely requires framework prescribed through regulatory rule and system changes that establish preference for one type of service over another
				Opportunities and incentives	◑	Alternative arrangements could result in DNSPs having less control over triggering local service events
				Allocation of risk	◑	The need for additional bid files could create greater risks, however alternative arrangement allows for optimisation with full visibility of all market preferences and available capacity (aiding the management of demand and supply balance)
				Overall	◑	Overall, the Project EDGE arrangement is less complex and would likely involve lower costs

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Table 4.4 continued MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score		Alterative Arrangements	Criteria and Score		Explanation
Data and settlement (network services) (#9)	9a) DER Aggregators transmit DER service-delivery verification data for use in LSE settlement to DSOs	Delivers value to consumers	◕	9b) 3rd Party (such as a metering coordinator) transmits DER service delivery verification data for use in LSE settlement to DSOs using pattern approved standardised metering data (NMI institute under the Trade Act)	Delivers value to consumers	◕	Depends on the DER service-delivery verification data required by DSOs. If it is based on what devices did the DER Aggregator would likely be best placed however if it is what the import or export was in a specific location the metering coordinator would likely be best placed.
		Efficiency	◕		Efficiency	◕	
		Adaptability	◑		Adaptability	◕	The number of DER Aggregators is expected to increase over time. Changes in regulations could introduce a level of inflexibility if DER Aggregators apply different standards (e.g., driven by factors such as geography)
		Opportunities and incentives	◑		Opportunities and incentives	◑	Minimal variance between arrangements
		Allocation of risk	◕		Allocation of risk	◕	The optimal arrangement is dependent on the DER service-delivery verification data required by DSOs.
		Overall	◕		Overall	◕	The optimal arrangement is dependent on the DER service-delivery verification data required by DSOs.

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Table 4.4 continued MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score		Alterative Arrangements	Criteria and Score		Explanation
Connecting DER (#12) – DOE compliance monitoring	12.1a) DSOs monitoring compliance with DOEs	Delivers value to consumers	◑	12.1b) 3rd party (such as a metering coordinator) automatically monitors compliance with DOEs using logic and limits within the meter pre-defined by the DSO. The data is pattern approved standardised metering data (NMI institute under the Trade Act) used for energy market settlements. Flags for non-conformance with these limits are provided by exception to the DSO to make a DOE compliance assessment.	Delivers value to consumers	◕	The Project EDGE arrangement requires additional data 'touchpoints' (e.g., constantly pulling data for DSOs to analyse), likely increasing overall costs
		Efficiency	◑		Efficiency	◕	
		Adaptability	◑		Adaptability	◑	
		Opportunities and incentives	◑		Opportunities and incentives	◑	Minimal variance between arrangements
		Allocation of risk	◕		Allocation of risk	◕	
		Overall	◑		Overall	◕	Overall, the alternative arrangement could lower costs given DSOs not constantly pulling data to analyse, instead can be done in an automated

Table 4.4 continued MCA assessment of selected functions from OpEN

Function	Project EDGE Arrangement	Criteria and Score	Alterative Arrangements	Criteria and Score	Explanation
Connecting DER (#12) – DOE compliance enforcement	12.2a) DSOs enforcing compliance with DOEs based on a DSO-defined penalty framework	Delivers value to consumers	12.2b) AER establishes and maintains an approved framework of DOE compliance with rectification measures ranging from 'firm' e.g., a period of disconnection from grid (in the case of a cyber-attack) or removal from DER Aggregator portfolio to 'soft' e.g., fines.	Delivers value to consumers	The Project EDGE arrangement requires additional data 'touchpoints' (e.g., constantly pulling data for DSOs to analyse), likely increasing overall costs.
		Efficiency		Efficiency	
		Adaptability		Adaptability	
		Opportunities and incentives		Opportunities and incentives	Minimal variance between arrangements
		Allocation of risk		Allocation of risk	The inclusion of the AER could further build trust in the market for DER Aggregators
		Overall		Overall	Overall, the alternative arrangement could further build trust in the market for DER Aggregators. In addition, involvement of the AER could further build trust in the market amongst consumers and ensure a clearer separation of duties.

The Project EDGE arrangement of roles and responsibilities underpins the realisation of benefits identified in the CBA.

The key feature of the Project EDGE arrangement of roles and responsibilities involves DER Aggregators, on behalf of DER customers, receiving the necessary external signals (such as prices and constraints) and co-optimising DER portfolios across wholesale and business-to-business (B2B) opportunities.
This allows:

- Prioritisation of the interests of DER customers in how their DER is utilised – this is particularly important in a voluntary, market-based arrangement where customers who have invested in DER need to perceive clear value in participating in the NEM through a DER Aggregator.
- Streamlined visibility with all service capacity (for market and B2B services) of a portfolio represented in a common portfolio level bid to the market operator.
- Opportunities for value-stacking which can allow for greater value customer products and cost efficiencies to be realised by DER Aggregators.
- An appropriate allocation of risks and incentives as DER Aggregators are responsible for optimising DER resources while acting in compliance with market rules and connection agreements.

The Project EDGE arrangement of roles and responsibilities is aligned with the National Electricity Objective (NEO) and promotes efficiency by extending current roles and responsibilities rather than creating new or duplicating existing ones.

5
Implications of the CBA

CBA Findings

The CBA found that the broad deployment of DOEs for many DER Customers and the establishment of a scalable data exchange hub are short-term priorities necessary for the longer-term delivery of value from DER

5.1 Optimal DER Investment Pathway

Acknowledging cross industry reform efforts to date, unlocking value from DER coordination via VPP participation requires coordinated action. The CBA identified immediate foundational priorities to progress towards this outcome:

- **Increasing customer coverage of DOEs** as this enables greater DER export capacity
- **Increase visibility of DER for the Market Operator and DNSPs**, to enable situational awareness of DER in the NEM
- **Implementation of a scalable data hub to reduce data exchange costs** (a barrier to entry) for market participants (e.g., in accessing DOEs or gaining visibility of DER) and supports the development of additional DER service opportunities (including B2B services) that can support greater coordination of DER, which drives value to all consumers
- **Set clear roles and responsibilities** where DER Aggregators optimise DER on customers' behalf.

The CBA found there is merit in gradually introducing in a targeted manner more advanced DOE configurations (e.g., LV impedance model optimisation methodology and a maximise service DOE objective function). The introduction of these DOE configurations should be prioritised based on where DER are most constrained due to network capacity limits. While DOEs have the ability to release more network capacity for DER at times of constraint, realising the value of that additional capacity will require a sufficient proportion of installed DER to be connected under flexible connection agreements and made active through DER Aggregators.

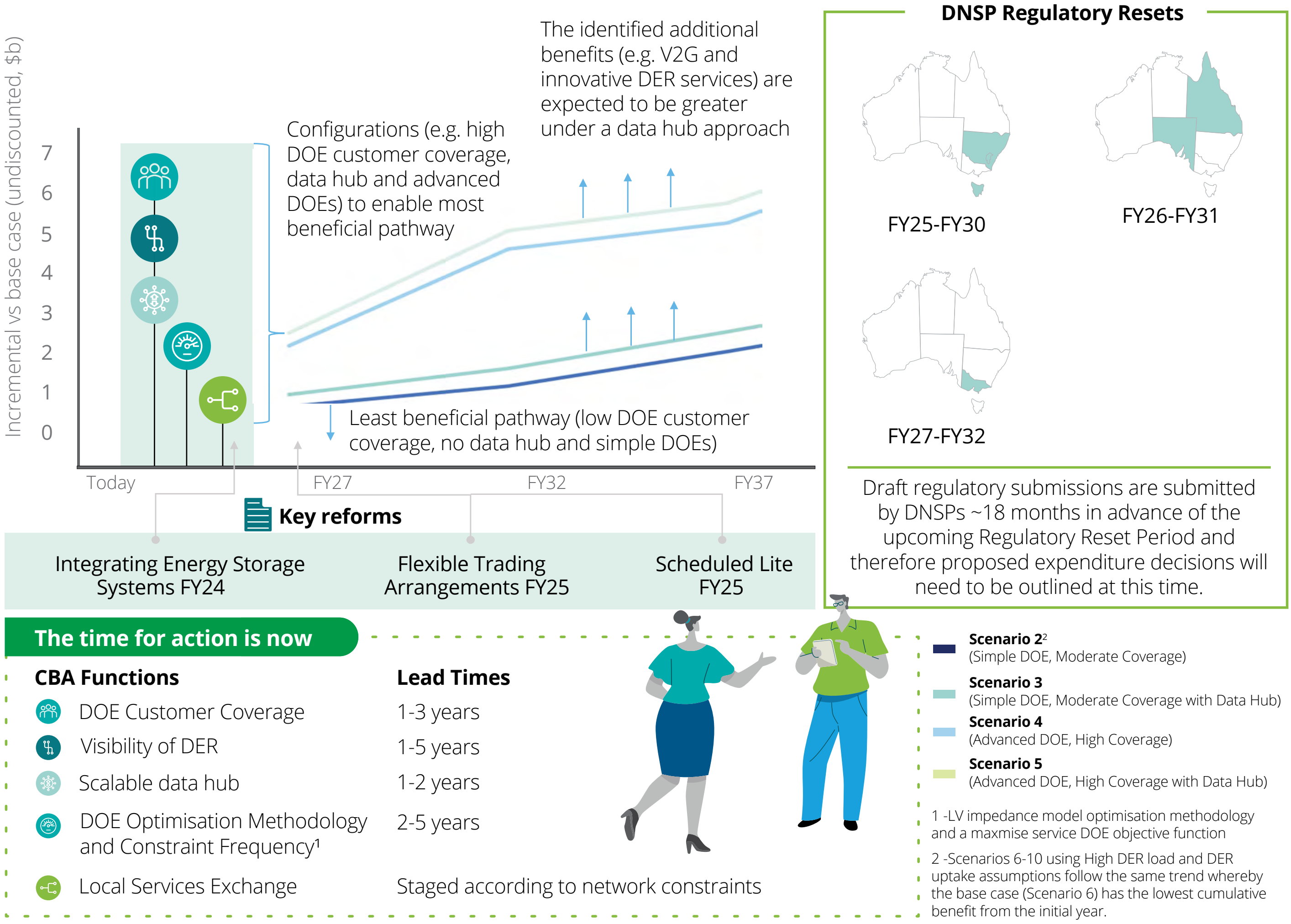
The optimal timing for the introduction of an LSE is less clear. While the Project EDGE field trial indicated that the LSE can technically deliver local network support services today, there are several factors that influence the value delivered by LSE. For example, LSE services are only viable where DER Aggregators can represent and offer sufficient DER capacity at concentrated locations where that support is required, as network constraints are by their nature locational and temporal[99]. As an initial step, DNSPs should consider targeting implementation of LSE for parts of the network with known constraints.

Figure 5.1 summarises a potential DER investment pathway for key industry capabilities, to realise the benefits identified in the CBA. This figure takes into consideration key upcoming market reform activities and estimated lead times for the implementation of the capabilities tested within the CBA, to help inform planning.

Ultimately, it highlights a DER investment pathway that hinges on focused and coordinated action from policy makers and market participants.

[99] S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).

Figure 5.1 DER Implementation Pathway



5.2 Key insights and takeaways across capabilities tested in the CBA

Based on the selected capabilities tested in the CBA scenarios, the following insights have been identified to support market participants progress the transition to a higher DER future.

Table 5.1 Key implications for industry to consider

Capabilities within the CBA	Insight	Implication	Timing
DOEs – customer coverage	DOE customer coverage is the key driver for delivering benefits by unlocking network capacity so that more DER can be coordinated via VPPs.	**The enablement of flexible export limits** must be prioritised to support DOE customer coverage; dynamic connection agreements can do this if consumers are incentivised clearly. To promote DOE customer coverage, further work is required to inform consumers of the benefits of DER integration and **to build social licence** with consumers. Importantly, issues around fairness, transparency of value to consumers and trust need to be sufficiently addressed.	1-3 years

Table 5.1 continued Key implications for industry to consider

Visibility of DER	The Market Operator and DNSPs having sufficient visibility of DER is critical to ongoing secure and reliable electricity supply.	The Market Operator should be focused on **building capabilities to know how and in what volumes DER generation/ load will respond to prices and the impact this will have on the market and the ability to forecast effectively**. This is aligned with current reform initiatives such as the proposed **Scheduled Lite**[100] rule change. DNSPs should be focused on **investment to uplift monitoring and management of their LV networks and connected DER**. This will require DNSPs to invest in **monitoring systems and digital platforms** to increase visibility and control. These investments will be critical to supporting the increased utilisation of network assets and allowing more of the expanding volume of DER to be brought to market.	1-5 years

[100] AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite

Table 5.1 continued Key implications for industry to consider

Scalable Data Hub	A data hub approach to scalable DER data exchange will reduce costs and allow new DER-based service innovations to be more easily adopted compared to a point-to-point approach.	**Implementation of a scalable data hub** that provides standardised data services such as DER registration, identity verification and reporting should be prioritised to reduce DER data exchange costs for market participants (e.g., in accessing DOEs or gaining visibility of DER) and facilitate improved access to additional DER services (including B2B services) that can support greater coordination of DER, which drives value to all consumers.	1-2 years
DOEs – optimisation methodology and constraint optimisation frequency	There is merit in gradually introducing more advanced DOE configurations (e.g., LV impedance model optimisation methodology and a maxmise service DOE objective function).	**DNSPs will need to target implementation of DOEs that are optimised** for a given network segment and DER penetration level.	Next 5 years
LSE	The value of a local service is realised in the presence of network constraints which are locational and temporal.	**A targeted approach should be taken to implementing an LSE** based on network needs. Barriers to its adoption could be lowered by exchanging the data through a scalable DER data hub and standardising its building blocks while still allowing flexibility to define fit for purpose services.	Staged according to network constraints

In addition, the CBA found that greater DER export capacity can lower electricity sector emissions in the NEM. Therefore, the introduction of an emissions reduction objective into the NEO to help drive emissions reduction across the NEM will further highlight the benefits associated with the integration of active DER in the NEM.

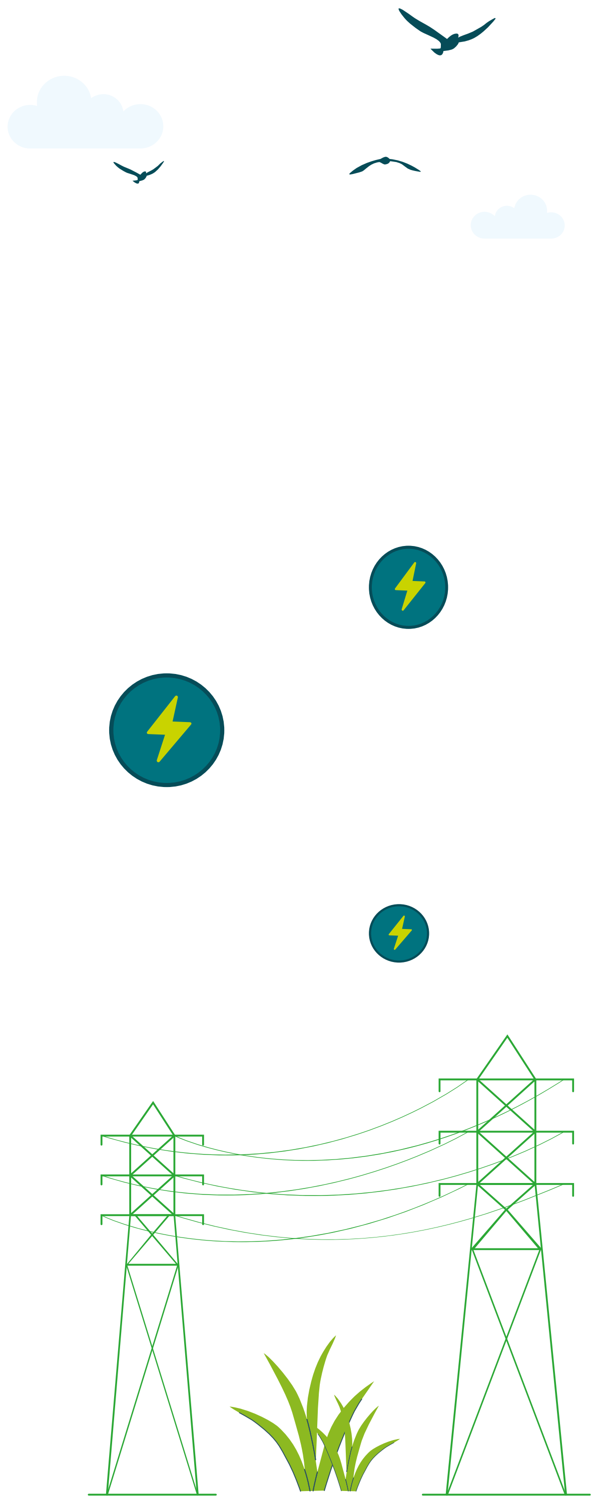
5.3 Conclusion

Building on the immediate foundational priorities for unlocking the benefits of DER, this CBA demonstrates that a coordinated market-based approach to DER integration within the NEM whereby DER Aggregators and Retailers represent DER Customer needs is economically feasible and can deliver value to all electricity consumers.

There is an immediate opportunity unlock the benefits of DER by:

- **removing consumer constraints** on solar exports for as many customers as possible so all consumers can benefit from VPPs coordinating DER
- **setting the rules** for efficient DER coordination with a clear set of roles and responsibilities for market participants
- **laying the foundations** for DER market-enablement with an efficient and scalable data exchange approach to reduce costs and expand consumer choice.

Timely action in implementing the capabilities identified in this CBA will help realise considerable consumer value, drive emissions reduction and help secure, reliable operation of the NEM as we move towards a higher DER future.



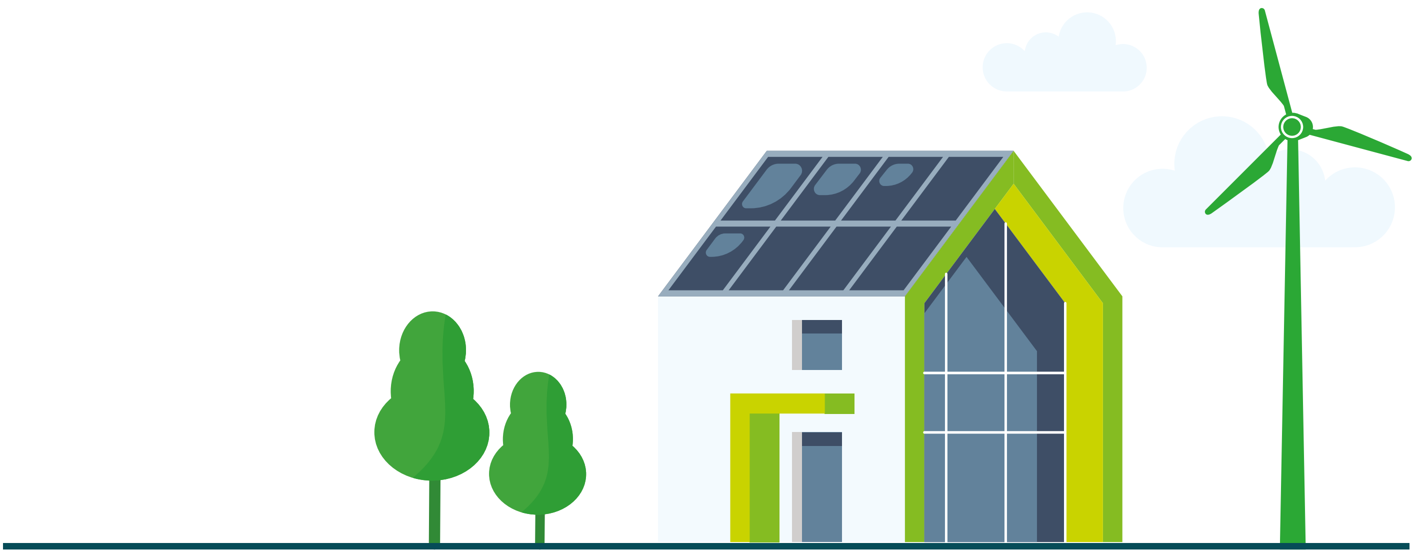
Appendix A – CBA Mapping

Project EDGE set out a Research Plan[101] to map the work program it was seeking to undertake. The Research Plan identified key areas of focus for Project EDGE, a subset of which are relevant to the CBA. Table A.1 maps the Research Plan research questions and associated hypotheses relevant to the CBA.

The CBA utilised the following assessment classifications to assess how the CBA findings have supported the hypotheses presented in the Research Plan. Each classification assigns a level of confidence per CBA findings, recognising that Project EDGE has multiple streams that only when considered together can fully determine (i.e., confirm or reject) the outcome of the hypotheses.

Assessment Classifications:

- **Supports** – all aspects of the hypotheses
- **Partially supports** – only some aspects of the hypotheses
- **Inconclusive** – insufficient evidence
- **Partially contradicts** - only some aspects of the hypotheses
- **Contradicts** - all aspects of the hypotheses.



[101] UoM, Project EDGE Research Plan (February 2022), at https://aemo.com.au/-/media/files/initiatives/der/2022/master-research-plan-edge.pdf?la=en&hash=257274509C75943903E2EE7A17954C35

Table A.1 CBA mapping to the Research Plan[102]

CBA relevant Research Question (RQ)	Associated Hypotheses (Hp)	Assessment Classification of Relevant CBA Findings	Relevant Sections in the CBA Report
RQ.1 How can the integration of DER into the NEM be designed to enable simple customer experiences, deliver the needs of DER customers, and improve social license for active DER participation?	**Hp.C** Enabling DER Aggregators to deliver multiple services whilst minimising market complexity can enable them to provide valuable and simple offers to customers to activate their DER.	**Partially supports** - Minimising complexity when integrating DER into the NEM is beneficial for enabling DER Aggregator participation. Standardisation can support the delivery of multiple services (market and network support services) by minimising operational friction. This is important given the potential complexity for DER Aggregators participating across many DNSP service areas. Specifically, the CBA found that: • A data hub approach to scalable DER data exchange, compared to a point-to-point approach, can reduce complexity and cost for DER Aggregators (up to $0.23b across the 20-year time horizon) through simplifying integration, identity verification and reporting between participants. Minimising complexity is shown to reduce costs for DER Aggregators which in turn could enable them to serve DER Customers at a lower cost. However, the CBA did not test the impact of DER market configurations on potential DER Aggregator customer offerings. The CBA found that greater uptake of active DER can reduce emissions (t-CO2e) through displacing technology types with greater emissions intensity. This could improve the social license[103] for active DER participation going forward.	Methodology – Section 2.1.1 and Section 2.2.4 Findings - Section 3.2.1, Section 3.2.5 and Section 3.3

[102] Table A.1 only includes research questions and associated hypotheses relevant to the CBA.
[103] AEMO (October 2022), General Community Perceptions of DER, at https://aemo.com.au/-/media/files/initiatives/der/2022/community-perceptions-of-der-and-aggregation-services.pdf?la=en This report noted that emissions reduction (CO2) is a driver for the uptake of DER.

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Table A.1 continued CBA mapping to the Research Plan

CBA relevant Research Question (RQ)	Associated Hypotheses (Hp)	Assessment Classification of Relevant CBA Findings	Relevant Sections in the CBA Report
RQ.2 Does the integration of DER into the NEM promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers?	**Hp.A** The integration of DER into the NEM can deliver net positive economic impacts for all consumers, particularly if started simply and developed progressively as DER penetration increases	**Partially supports** -The integration of DER can increasingly deliver benefits to all consumers as DER penetration increases. Specifically, the CBA found that: • Introducing more advanced DOEs and market configurations (e.g., data hub) at higher levels of DER penetration can result in greater benefits. This is demonstrated via an incremental benefit of $6.04b between Scenario 10 and the base case (Scenario 6) compared to an incremental net benefit of $5.15b between Scenario 5 and the base case (Scenario 1). • Based on the CBA, there is limited evidence to suggest that starting 'simply' (e.g., simple DOE configurations) is preferred given the cumulative incremental benefit is greatest at the conclusion of the initial year in the Advanced DOE, High Coverage with Data Hub scenarios. However, the increased complexity could result in initial implementation challenges (e.g., timing and resource constraints). As such, from an operational perspective, there could be rationale for prioritising the introduction of more advanced DOEs based on where DER are most constrained due to network capacity.	Methodology – Section 2.1.1 Findings - Section 3.1

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Appendix A – CBA Mapping 92

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Table A.1 continued CBA mapping to the Research Plan

CBA relevant Research Question (RQ)	Associated Hypotheses (Hp)	Assessment Classification of Relevant CBA Findings	Relevant Sections in the CBA Report
RQ.2 Does the integration of DER into the NEM promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers?	**Hp.B** DER delivery of local services enable DNSPs to defer investments and efficiently manage network reliability and ensure best long-term outcomes for all consumers.	To simplify the process of assigning a value to the use of an LSE to reduce DER export curtailment[104] the CBA has derived an average price associated with reduced curtailment[105], using the 2022 customer export curtailment values (CECV) published by the AER[106]. This price has been applied to the forecast annual volume of curtailed exports[107]. The CBA found that across the 20-year time horizon[108] the implementation of an LSE (with data exchange via a data hub) can result in an incremental benefit of up to $0.08b[109] under the AEMO ISP Step Change assumptions and up to $0.51b[110] under the High DER uptake assumptions based only on the use of an LSE to reduce DER export curtailment.	Methodology – Section 2.2.4 Findings - Section 3.3.2
	Hp.C A data hub model reduces cost and complexity of data exchange and provides an economically efficient and scalable approach for integrating DER into the NEM.	**Supports** – A data hub model would provide a lower cost approach for scalable DER data exchange between participants, compared with an approach with many point-to-point interactions, by reducing the number of integrations, as each participant only needs to integrate with one industry data hub. The CBA found that across the 20-year time horizon[111], a centralised data hub would reduce costs by up to $0.44b and a decentralised data hub would reduce costs by up to $0.45b compared to a point-to point approach. In addition, a data hub as compared to a point-to point approach could deliver further upside through facilitating new DER-based service innovations more easily and at lower cost as it simplifies integration, identity verification and reporting between participants.	Methodology – Section 2.2.4 Findings - Section 3.3.1

[104] UoM analysis suggests that reactive power services from DER can be applied to relieve export constraints in the low voltage network as exports are typically limited by voltage limits rather than the thermal ratings of network assets. Refer to S. Riaz, J. Naughton, University of Melbourne, Project EDGE: Deliverable 8.1: Final report on DER services co-optimisation approaches (March 2023).

[105] The calculation is based on using a CECV average value across the NEM over the 20-year CBA time horizon of $48.38/MWh.

[106] AER, 2022. Final CECV Methodology, at https://www.aer.gov.au/system/files/Final%20customer%20export%20curtailment%20value%20methodology%20-%20June%202022.pdf

[107] Based on the Energeia Techno-economic modelling (TEM) outputs for potential avoided voltage constraint curtailment (post DOE configurations tested within this CBA scenarios) over the 20-year CBA time horizon.

[108] This CBA assumes for the purposes of assessing the LSE that there will be 13 DNSPs by FY42 each integrating with on average 7 DER Aggregators/Retailers/OEMs and assumes that there will be 13 DER Aggregators/Retailers/OEMs by FY42 each integrating with on average 3 DNSPs.

[109] Scenario 3 - Simple DOE, Moderate Coverage with Data Hub (AEMO ISP Step Change).

[110] Scenario 8 - Simple DOE, Moderate Coverage with Data Hub (High DER).

[111] This CBA assumes for the purposes of assessing the scalable DER data exchange approaches that there will be 13 DNSPs by FY42 each integrating with on average 27 DER Aggregators/Retailers/Original Equipment Manufacturer (OEM) and assumes that there will be 52 DER Aggregators/Retailers/OEMs by FY42 each integrating with on average 6 DNSPs. The number of DER Aggregators/Retailers/OEMs has been informed by the current number of market participants in the NEM currently offering VPPs, the NEM Registration and Exemption List and the VPP uptake assumptions used in this CBA. It is assumed that not all DER Aggregators/Retailers/OEMs using the DER data exchange will participate on the spot market (e.g., some will only be using the DER data exchange for the purposes of FCAS and business-to-business (B2B) services).

Appendix A – CBA Mapping 93

Project EDGE CBA – Final Report

Table A.1 continued CBA mapping to the Research Plan

CBA relevant Research Question (RQ)	Associated Hypotheses (Hp)	Assessment Classification of Relevant CBA Findings	Relevant Sections in the CBA Report
RQ.2 Does the integration of DER into the NEM promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers?	**Hp.D** The roles and responsibilities of market participants that best deliver on the NEO under the Hybrid Model are largely aligned to their current roles under the existing regulatory frameworks.	**Supports** – The Project EDGE arrangement of roles and responsibilities comprised DER Aggregators, on behalf of DER customers, receiving the necessary external signals (such as prices and constraints) and optimising DER portfolios across wholesale and business-to-business (B2B) opportunities (e.g., network support services). This allows: • Prioritisation of the interests of DER customers in how their DER is utilised – this is particularly important in a voluntary, market-based arrangement where customers who have invested in DER need to perceive clear value in participating in the NEM through a DER Aggregator • Streamlined visibility with all service capacity (for market and B2B services) of a portfolio represented in a common portfolio level bid to the market operator • Opportunities for value-stacking which can allow for greater value customer products and cost efficiencies to be realised by DER Aggregators • An appropriate allocation of risks and incentives as DER Aggregators are responsible for optimising DER resources while acting in compliance with market rules and connection agreements. The Project EDGE arrangement of roles and responsibilities is aligned with the National Electricity Objective (NEO) and promotes efficiency by extending current roles and responsibilities rather than creating new or duplicating existing ones	Methodology – Section 4 Findings - Section 4

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Appendix A – CBA Mapping 94

Project EDGE CBA – Final Report

Table A.1 continued CBA mapping to the Research Plan

CBA relevant Research Question (RQ)	Associated Hypotheses (Hp)	Assessment Classification of Relevant CBA Findings	Relevant Sections in the CBA Report
RQ.3 How does operating envelope design impact on the efficient allocation of network capacity while enabling the provision of wholesale energy and local network services?	**Hp.A** The design of the operating envelopes has a material impact on the network operation and provision of different wholesale energy and local services.	**Supports –** The design of the dynamic operating envelope (in terms of optimisation frequency, optimisation methodology and the objective function for network capacity allocation to customers) has a material impact on the benefits. Specifically, the CBA found: • A relatively minor enhancement of the DOE objective function towards a maximise service function (from a nameplate function) and of the DOE constraint optimisation frequency towards daily frequency (from annual frequency) results in an incremental benefit of up to $1.33b[112] under the AEMO ISP Step Change assumptions and up to $1.83b[113] under the High DER assumptions.	Methodology – Section 2.1.1 Findings - Section 3.1
	Hp.B Accounting for uncertainty in the calculation of operating envelopes improves the technical and economic outcomes of the integration of DER into the NEM.	**Supports** – As shown above accounting for and reducing the level of uncertainty in the calculation of dynamic operating envelopes can improve economic outcomes. For example, uncertainty can be reduced via a) a more frequent constraint optimisation (e.g., intra daily vs daily), and b) the methodology that DNSPs use to set their DOE limits for participating DER (e.g., LV impedance model vs Approximation) and c) the DOE objective function (e.g., maximise service vs nameplate).	Methodology – Section 2.1.1 Findings - Section 3.1

[112] Scenario 2 - Simple DOE, Moderate Coverage (AEMO ISP Step Change assumptions).
[113] Scenario 7 - Simple DOE, Moderate Coverage (High DER assumptions).

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Appendix A – CBA Mapping 95

Appendix B – Visibility of DER

This section provides additional detail on the CBA findings outlined in section 3.3.3 related to visibility of DER.

The CBA focused on the incremental shift from a defined **current state** (i.e., before Scheduled Lite[114] and SCADA Lite[115] implementation) where there is visibility of DER based only on:

- DER participating in the wholesale demand response (WDR) mechanism[116]
- The demand side participation information portal
- the DER Register,

to a **future state** where DER in VPPs is fully scheduled ('visibility with controllability') and aligned with appropriate technical and performance standards.

In the CBA, the base cases assume alignment with the defined current state, while all other scenarios assume alignment with the defined future state.

The findings are presented across the Market Operator, DNSPs and DER Aggregators. The costs and benefits are limited to those directly associated with the defined uplift from current state to future state in visibility of DER.

Market Operator

To support the integration of DER into the NEM, the Market Operator requires the following key capabilities:

- Visibility through near real time portfolio telemetry and bids
- Predictability (via generated forecasts) through transparency on DER Aggregators' actions and the ability to factor in this information while undertaking functions to balance supply and demand
- Controllability (via dispatch instructions to DER Aggregators).

Table B.1 outlines the costs for the Market Operator associated with the defined uplift in key capabilities.

[114] AEMO, at https://aemo.com.au/en/initiatives/trials-and-initiatives/scheduled-lite

[115] SCADA Lite is part of the NEM 2025 roadmap and has been identified as a foundational initiative. SCADA Lite aims to reduce entry barriers for smaller generators and demand side resources to provide greater visibility to AEMO and to participate in the market with SCADA that is fit for purpose for DER.

[116] The WDR mechanism allows demand side (or consumer) participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. The WDR Mechanism has a range of eligibility requirements including customer load size.

Table B.1 Costs[117] for the Market Operator associated with the defined uplift in visibility of DER (20-year time horizon, $FY23, 4.83% discount rate)

Cost Category	Description and methodology (if applicable)	Key assumptions	$
Forecasting short-term network state (e.g., constraint forecasts)	Forecasting system updates across a selected part of the network (including for weather conditions) to enhance the constraint evaluation capabilities of the future network state.	The establishment costs are spread across the initial 3 years based on 5 Minute Settlement (5MS) taking ~4 years between program establishment and commencement (a more complex program implementation). The maturing costs are incurred in FY28 and FY29 to accommodate a further short-term uplift in DER uptake. These costs are based on the Baringa Partners, Assessment of Open Energy Networks Frameworks[118] and were further validated during Project EDGE by AEMO.	Establishment costs: $0.83m Maturing costs: $0.43m Total: $1.26m

[117] Where necessary cost categories have been scaled to only include the proportion of total cost relevant to the defined uplift in visibility of DER.

[118] Baringa Partners (May 2020), Assessment of Open Energy Networks Frameworks, at http://www.energynetworks.com.au/resources/reports/2020-reports-and-publications/assessment-of-open-energy-networks-frameworks/

Table B.1 continued Costs[119] for the Market Operator associated with the defined uplift in visibility of DER (20-year time horizon, $FY23, 4.83% discount rate)

Cost Category	Description and methodology (if applicable)	Key assumptions	$
NEM 2025 Work Package 2 Visibility	Scheduled Lite and SCADA Lite as per AEMO's Gate 1 business case for the NEM2025 reform program[122].	These costs are based on the NEM2025 Work Program - Work Package 2 Visibility (Scheduled Lite and SCADA Lite) and were further validated during Project EDGE by AEMO. This is a 10-year work program with costs for Work Package 2 Visibility allocated across program implementation costs (9%), initiative implementation costs (48%), upfront technology costs (5%) and operating costs (38%). All upfront and implementation costs are spread across the initial 3 years. To align with the 20-year time horizon, the operating costs have been extended at the same cost per annum.	Program implementation costs: $2.99m Initiative implementation costs: $14.97m Upfront technology costs: $1.71m Operating costs: $16.62m Total: $36.30m
Total			**$37.56m**

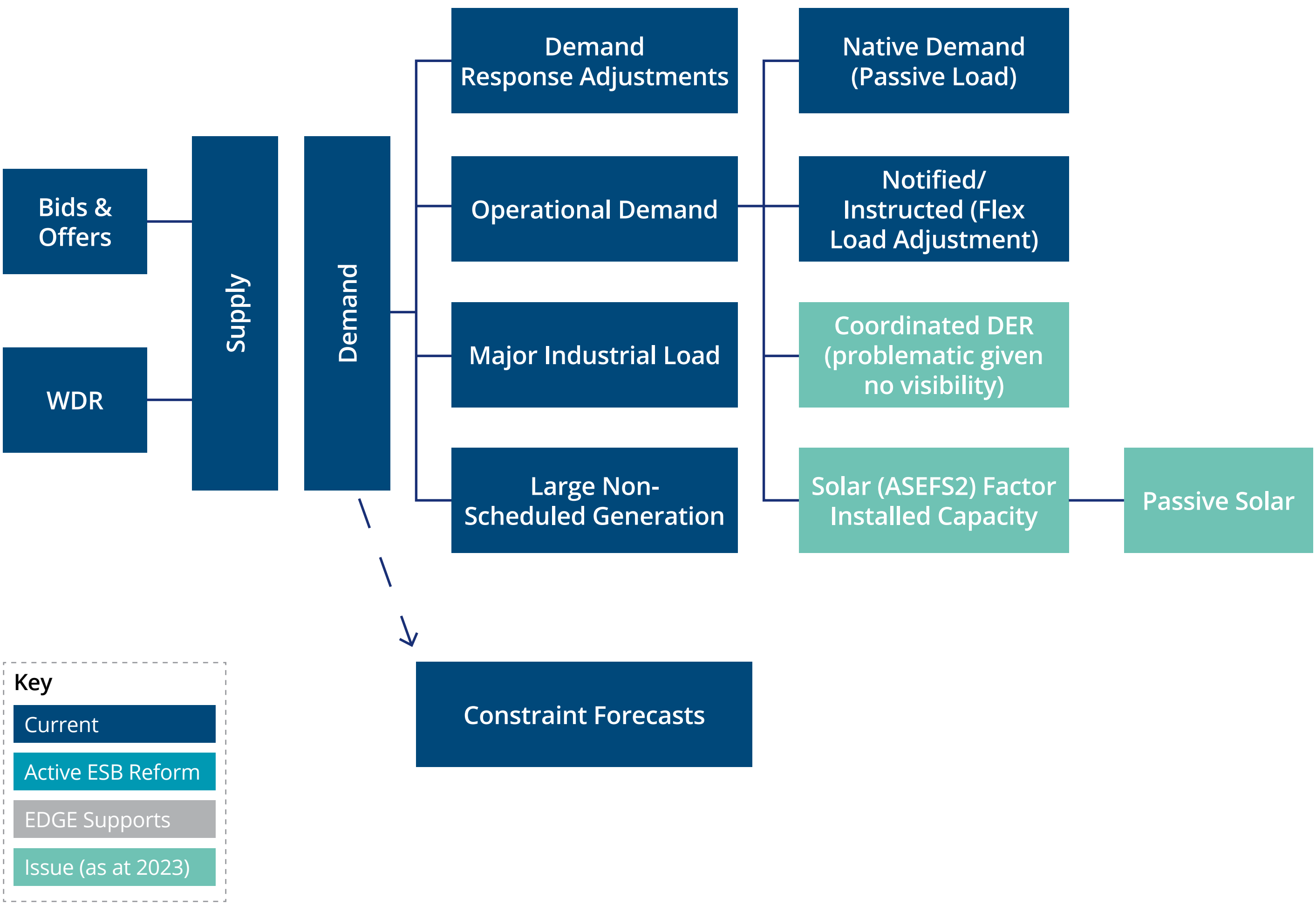
[119] AEMO (August 2022), Gate 1 business case for the NEM2025 reform program, at https://aemo.com.au/-/media/files/initiatives/regulatory-implementation-roadmap/reform-update-v1/nem2025-gate-1-business-case-industry-version.pdf?la=en.

To obtain the visibility of DER required to maintain network security and reliability in a future with greater DER, the Market Operator will need either:

- Flex bidding[123]
- Net NMI bidding[124] but with data that provides the visibility of the flexible portion[125].

Figures B.1, B.2 and B.3 outline current forecasting mechanisms for the Market Operator and how this differs (i.e., the uplift in capabilities compared to the current state) with Flex or Net NMI bidding.

Figure B.1 Market Operator current forecasting mechanisms



Notes: Demand forecasts feed into thermal and voltage constraints which limit the ability for Large Generators (supply side) to be dispatched. The issues with demand forecasting have flow on impacts to other areas of the system (e.g., system constraints).

Figure B.2 Market Operator forecasting mechanisms (Flex)

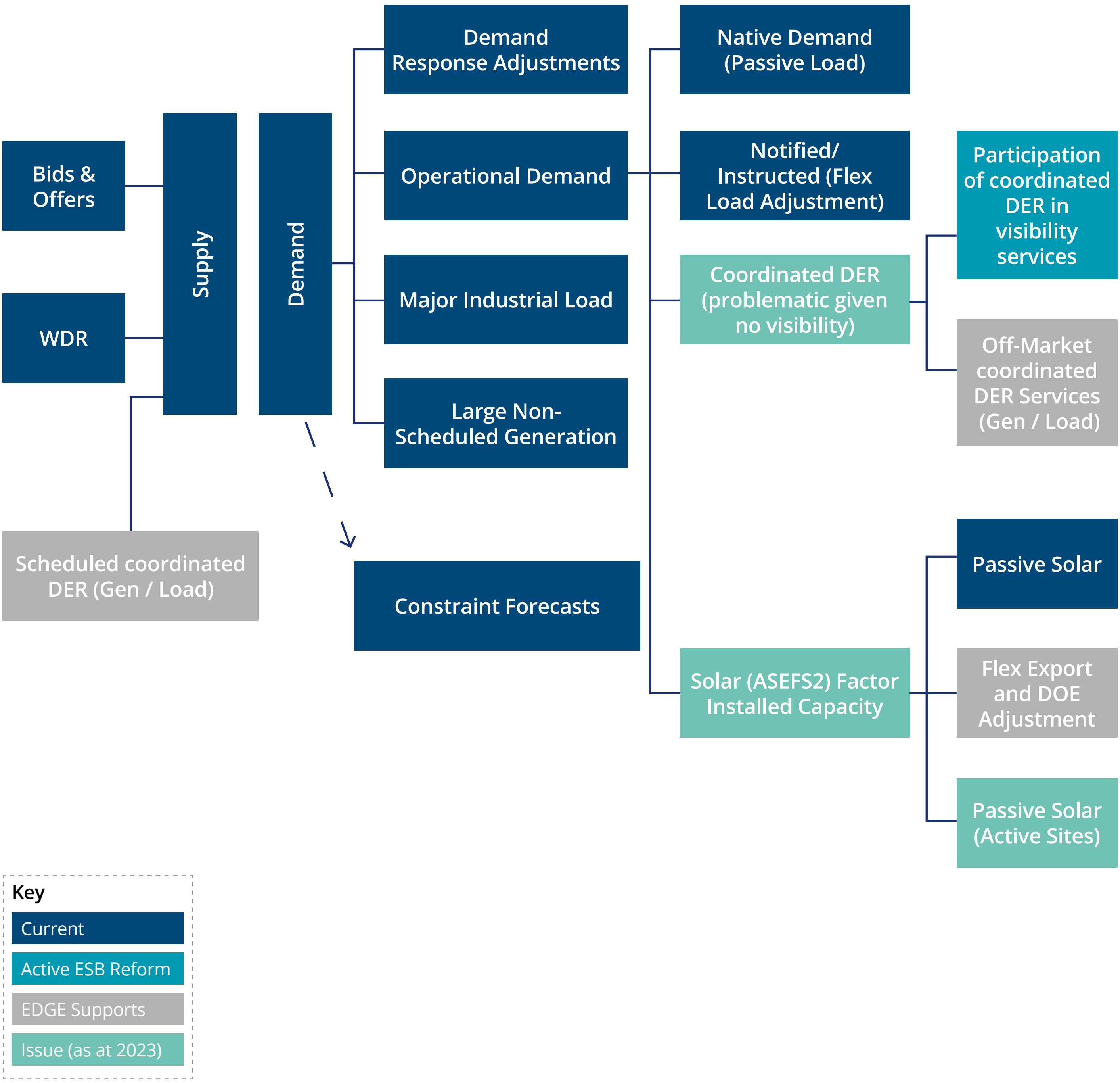
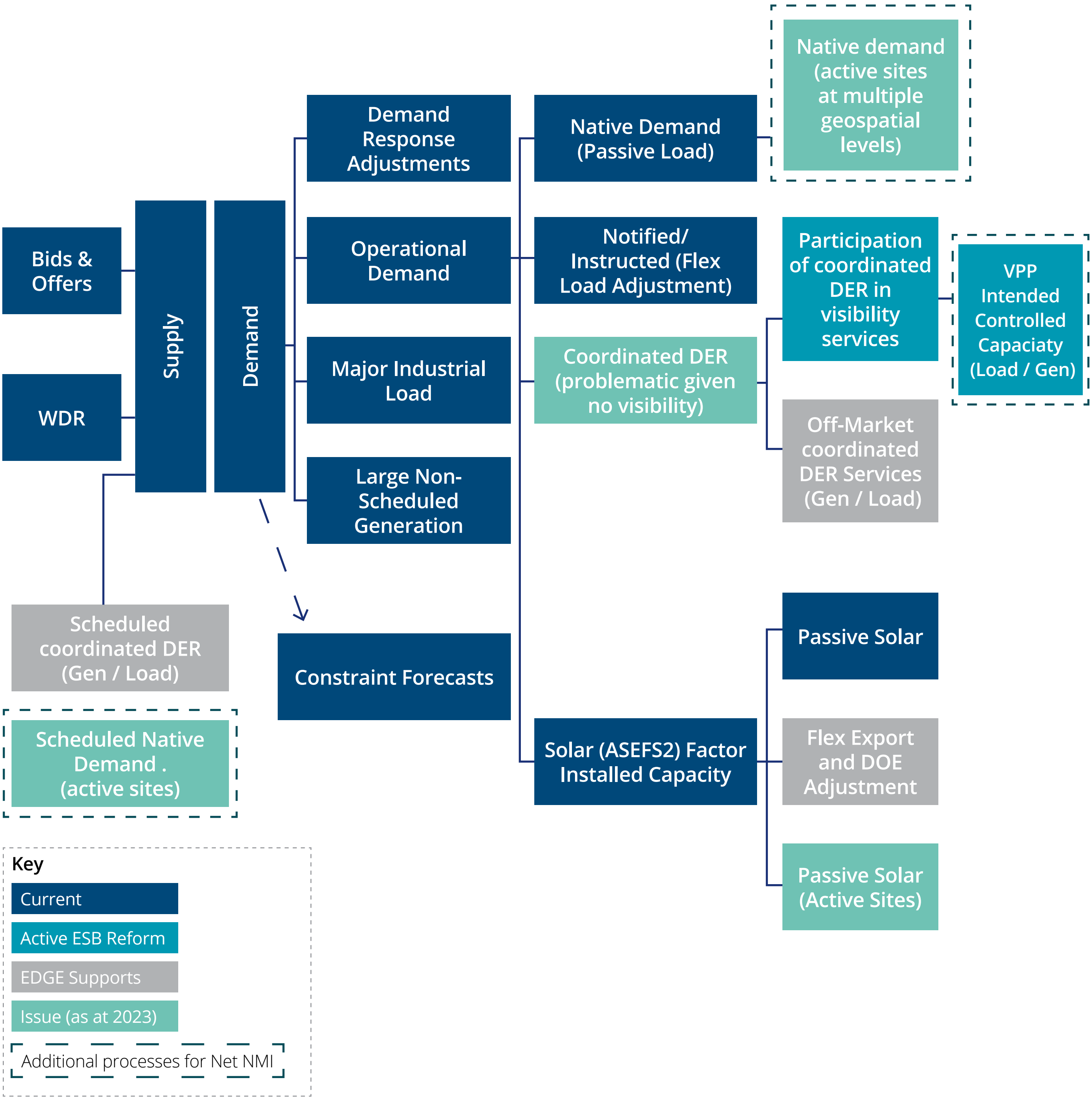


Figure B.3 Market Operator forecasting mechanisms (Net NMI)



Notes:

- Native demand (supply side) for active sites is classed as a current issue because AEMO's Native Demand forecasts are at an abstracted level and not site specific
- Native demand (demand side) is only feasible if the telemetry arrangement is as per Project EDGE (5-minute demand trace)
- Receiving a portfolio level uncontrolled load forecast with Net NMI does not separate visibility of controlled generation from controlled load.

The level of operational risk for the Market Operator will differ based on the bidding mode.

As Net NMI does not separate 'controlled' DER load/generation from the 'uncontrolled' DER load/generation, the Market Operator is required to forecast with less certainty. As a result of reduced forecasting certainty, the Market Operator would be required to maintain greater operating reserves.

Table B.2 outlines the costs for the Market Operator to adapt its systems and capabilities to utilise DER Aggregator bids, contrasting both Flex and Net NMI. These costs were validated during Project EDGE by AEMO.

Table B.2 Costs for the Market Operator under Net NMI vs Flex

Cost Category	Key assumptions (if applicable)	Net NMI	Flex
Integrate DOE Model (to offset the passive solar forecast when required)	Capex: $2.0m (allocated across the initial 2 years with 70% in year 1 and 30% in year 2 – same for other capex below)) Opex: $0.10m per annum	$3.15m	$3.15m
Determine VPP intended control capacity	Capex: $0.50m Opex: $0.05m per annum	$1.10m	Not Applicable
Non-registered off-market services (netted from the operational demand forecast)	Capex: $2.0m Opex: $0.10m per annum	$3.15m	$3.15m
Solar forecast adjustments (for active site bids)	Capex: $0.30m Opex: $0.02m per annum	$0.54m	$0.54m
Adjust forecast using Net NMI bid adjustment	Capex: $0.50m associated with bidding and dispatch processes	$0.47m	Not Applicable[120]

[120] Changes to the demand forecasting system will be more complex under Net NMI.

Table B.2 continued Costs for the Market Operator under Net NMI vs Flex

Additional model retraining for Net NMI bid adjustment	Capex: $0.40m Opex: $0.020m per annum	$0.63m	Not Applicable
Additional shadow forecast to validate new adjusted demand forecast	Capex: $2.0m Opex: $0.10m per annum	$3.15m	Not Applicable
Total		**$12.17m**	**$6.83m**

While, both bidding modes are expected to result in greater visibility of DER for the Market Operator going forward, Net NMI bidding has greater costs (~$5.34m in NPV terms across the 20-year horizon) and residual risk compared to Flex bidding.

Table B.3 outlines the benefits for the Market Operator associated with the defined uplift in visibility of DER using Flex bidding. These benefits are based on enhanced visibility and controllability of DER to manage real time operations and operational forecasting.

Table B.3 Benefits[121] for the Market Operator associated with the defined uplift in visibility of DER (20-year time horizon, $FY23, 4.83% discount rate)

Benefit Category	Description and methodology (if applicable)	Key assumptions	$ - AEMO ISP Step Change assumptions	$ - High DER assumptions
Reduced risk of RERT events	Enhanced visibility can ensure more accurate demand forecasts (via better situational awareness and increased certainty) reducing the need for the procurement of RERT.	The average RERT total cost per annum across the NEM over the last 3 years is $59.88m[122].	$60.53m	$84.74m

[121] These benefits have not been informed by the Project EDGE field trial. Where necessary benefit categories have been scaled to only include the proportion of total benefit relevant to the defined uplift in visibility of DER.

[122] AEMO, at https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting

Reduced risk of load shedding events	Enhanced visibility can ensure more accurate demand forecasts (via better situational awareness and increased certainty) reducing the risk of load shedding.	During the load shedding event in Victoria on 25 January 2019[123] 270.8 MW was shed impacting approximately 80,000 customers[124]. A value of customer reliability (VCR) of $45,951 per MWh was used to measure the cost to consumers.	$7.51m	$11.20m
Optimising DER to reduce peak demand	Enhanced visibility can ensure more accurate demand forecasts (via better situational awareness and increased certainty) at periods of peak demand. In the CBA this benefit is captured against 'DNSPs'.	AEMO has forecast that VPPs are expected to offset a material percentage of peak demand[125]. For the purposes of this assessment the assumed reduction in peak demand due to VPPs was extrapolated across the 20-year time horizon based on the AEMO ISP Step Change and High DER assumptions. The reduction in peak demand was valued using the long run marginal costs (LRMC) for DNSPs on the low voltage network.	$21.32m	$79.03m

[123] AEMO (April 2019), Load Shedding in Victoria on 24 and 25 January 2019 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf

[124] AER (March 2019), Electricity spot prices above $5000/MWh Victoria and South Australia,25 January 2019, at https://www.aer.gov.au/system/files/Prices%20above%20%245000MWh%20-%2025%20January%202019%20%28Vic%20and%20SA%29.pdf

[125] AEMO (August 2022), 2022 Electricity Statement of Opportunities, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of%20opportunities.pdf?la=en&hash=AED781BE4F1C692F59B1B9CB4EB30C4C

Reduced risk of system black events	Lack of visibility and controllability during at-risk periods could diminish the ability for the Market Operator to manage the power system through contingency events potentially leading to a system black in the most extreme circumstances. In the CBA this benefit is captured against 'Other', recognising it relates to broader 'whole of system' impacts.	The South Australian black system event of 28 September 2016 which impacted approximately 850,000 customers resulted in an estimated economic cost of $367m[126]. Using this historical event as a case study (extrapolating out the costs assuming 1 event of this magnitude per 6.6 years, an assumed uptake in electrification and that the magnitude of economic loss could have been higher had it occurred in a state with greater average annual consumption operational (sent out) per annum) to assess reduced risk due to greater visibility of DER.	$180.50m	$252.70m
Total			**$269.85m**	**$427.66m**

[126] Australian Energy Market Commission (12 December 2019), Mechanisms to enhance resilience in the power system – Review of South Australian Black System Event, at http://www.aemc.gov.au/sites/default/files/documents/aemc_-_sa_black_system_review_-_final_report.pdf.

DNSP

To support the integration of DER into the NEM, DNSPs will require visibility of the LV network operational status and network capacity utilisation.

Table B.4 outlines the costs for DNSPs associated with the defined uplift in capability. These costs were provided by AusNet[127] .

Table B.4 Costs[128] for the DNSPs associated with the defined uplift in visibility of DER (20-year time horizon, $FY23, 4.83% discount rate)

Cost Category	Description and methodology (if applicable)	Key assumptions	$ - AEMO ISP Step Change assumptions	$ - High DER assumptions
Gathering network data	Costs associated with collecting LV network operational status and network capacity utilisation via LV models, distribution transformer and smart meter measurement data. This also includes the costs associated with the necessary data cleansing.	Includes a fixed cost of $0.15m per DNSP. In addition, a variable cost of $0.015m per 10,000 customers.	$17.47m	$66.08m
Data transfer	Cost associated with data transfer to the Market Operator regarding how much LV network capacity exists and necessary data to ensure the DER Register can be maintained.	Includes a fixed cost of $0.01m per DNSP. In addition, a variable cost of $0.0025m per 10,000 customers.	$8.05m	$32.36m
Total[129]			**$25.97m**	**$98.44m**

[127] Noting these costs are likely to vary by DNSP. For example, AusNet has almost 100% penetration of smart meters which provide data utilised for the calculating DOEs.

[128] Where necessary cost categories have been scaled to only include the proportion of total cost relevant to the defined uplift in visibility of DER.

[129] Assuming 13 DNSPs by FY42.

DER Aggregators

To support the integration of DER into the NEM DER Aggregators require visibility through understanding each end point (where forecasting occurs) to ensure this information can be provided at an aggregated level to the Market Operator and DNSPs and to support the provision of DER Aggregator services.

Table B.5 outlines the costs for DER Aggregators associated with the defined uplift in capability. These costs were provided by Project EDGE DER Aggregator field trial participants and other DER Aggregators operating outside Project EDGE[130].

Table B.5 Costs[131] for DER Aggregators associated with the defined uplift in visibility of DER (20-year time horizon, $FY23, 4.83% discount rate)

Cost Category	Description and methodology (if applicable)	Key assumptions	$
Forecasting engine	Costs associated with the forecasting engine including training, model creation, model management and model execution. It assumes rolling 48-hour forecasting combined with more accurate near-term forecasts (with clustering to support scaling) per Project EDGE field trial.	Includes a fixed cost of $0.50m per DER Aggregator.	$22.36m
Data transfer	Costs associated with generating the telemetry files for AEMO.	Includes a fixed cost of $0.048m per DER Aggregator per annum.	$2.18m
Operational functions	Costs associated with the ICT support helpdesk, fleet registration and maintenance.	Includes a cost of $0.19m per DER Aggregator per annum on average.	$55.16m
Bid Modification	Costs associated with modifying the bid file (e.g., from Net NMI to Flex or vice versa) this cost is interchangeable regardless of the bidding mode.	Includes a fixed cost of $0.1m per DER Aggregator per annum.	$4.87m
Total[131]			**$84.57m**

[130] Where necessary cost categories have been scaled to only include the proportion of total cost relevant to the defined uplift in visibility of DER.

[131] Assuming 52 DER Aggregators/Retailers/OEMs by FY42.