DER INTEGRATION STRATEGY AND BUSINESS CASE

Regulatory Proposal 2024-2029

Endeavour Energy

POWER together

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Glossary

ADMS	Advanced Distribution Management System
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
BAU	business as usual
CBA	cost benefit analysis
AMI	Advanced Metering Infrastructure
DVMS	Dynamic Voltage Management System
ISP	AEMO's Integrated System Plan
VaDER	Value of Distributed Energy Resources
CECV	Customer Export Curtailment Value
DER	distributed energy resources
DMIA	Demand Management Innovation Allowance
DERMS	distributed energy resources management system
DOE	dynamic operating envelope
DSO	distribution system operator
ESB	Energy Security Board
ESS	essential system services
EV	electric vehicle
FIT	feed-in tariff
GIS	geographic information system
ICT	information and communications technology
kW	kilowatt
kWh	kilowatt-hour
LV	low voltage
LRMC	long run marginal cost
LVVA	low voltage visibility and analytics
NEM	National Electricity Market
NIEIR	National Institute of Economic and Industry Research

NPV	net present value
RCP	regulatory control period
SAIDI	system average interruption duration index
SRMC	short run marginal cost
VAR	volt-ampere reactive
VCR	value of customer reliability

1. Executive Summary

The transformation of the energy sector is accelerating. Our customers and our network are at the very centre of the change. Whether it be the huge popularity of rooftop solar, the increasing ubiquity of behind the meter and community energy storage, the rise of Electric Vehicles (EVs) and the rising ambitions of our community to achieve net-zero - there is a once in a lifetime transformation underway.

It is therefore imperative that we invest in ensuring customers have the ability to make energy choices and share in the costs and benefits of doing so in a fair and equitable manner. If we fail to respond to changing customer behaviour, the take-up of new technologies could be constrained and/or adversely impact the reliability and stability of the network.

DER integration is a relatively new category of expenditure that is primarily driven by the need to enable customers' future energy choices. This DER Integration Strategy has been developed to set a longer-term context and vision to guide and align DER integration investments in the Endeavour Energy network.

We sought customer and stakeholder views on the role they expect us to play in the decarbonisation of NSW and the decentralisation of the NEM as well as their expectations around DER service levels and how the costs of facilitating DER should be shared between customers.

Our Customer and Stakeholder Panel were strongly in favour of Endeavour Energy modernising the network in preparation for either a rapid or accelerated energy transition to accommodate future customer expectations as technology and markets evolve.

What Customers and Stakeholders Have Told Us

Customers have told us that the top priority service that customers want us to invest in is the ***enablement of Solar panel technology***. Specifically, customers are calling for the future grid to be one that is prepared to accommodate solar for anyone wanting to connect and export to the grid. Furthermore:

- Customers and stakeholders are keen to be involved in the transition to a low carbon economy and want Endeavour Energy to take steps to prepare for an accelerated transition, with customers considering further significant take-up of Solar Panels, Electric Vehicles (EVs) and Batteries.
- Customers aspired to the energy transition delivering a win-win outcome: a cleaner environment while also achieving personal savings through smarter, more efficient technologies and greater choice and control of their energy usage.
- There was therefore an expectation that Endeavour Energy increase its focus on technological innovation and implement smarter ways of serving customers and communities.
- Stakeholders were mindful of meeting customer expectations to generate and share their energy with minimal limitations on the uptake of DER to support a low carbon future and customer energy savings.
- Stakeholders were also concerned about the impact the transition to large scale renewable generation across NSW would have on electricity bills and the need to support the transition to DER in a fair and equitable manner for all customers

This customer feedback has shaped our DER integration plan within this Strategy which focuses on a range of cost-effective measures to further enable and optimise hosting capacity on the network.

Our Strategy and Approach

Our Strategy explores a long-term DER penetration forecast developed from AEMO ISP scenarios and is contextualised to Endeavour Energy's network and customer base.

We then assess DER hosting capacity using this forecast. To do so, we have developed a deterministic LV simulation tool in partnership with researchers at the University of Wollongong's Australian Power Quality and Reliability Centre (APQRC).

We are using this tool to quantify and value service outcomes (DER curtailment) using the AER's Value of DER (VaDER) methodology, of which a key input is the AER's Customer Export Curtailment Value (CECV).

A review of our current and past investments into DER integration is explored to track their effectiveness in delivering customer outcomes prior to developing a portfolio of credible and industry leading options for better integrating DER and equitably managing and sharing network hosting capacity. This is our DER Integration Plan.

Within our DER Integration Plans we also detail how tariff reform will be used to accommodate the forecast and reduce network investment as well as our plans to implement Dynamic Operating Envelopes.

Our Plans

We are proposing a total DER Integration investment of **$81m** for the FY2024-29 period. This investment will make a significant contribution to customer and environment benefits with an estimated unlocking of 6000GWh of renewable energy to what otherwise be lost through curtailment. The summary of our DER Integration investment by category is shown below in Table 1.

Table 1 – DER Integration investment summary (Real $m FY24 base year)

Investment Category	opex	Network capex	ICT capex	Total (RCP24-29)	Alleviated Curtailment
Total	**$31.0m**	**$45.1m**	**$5.0m**	**$81.2m**	**6000GWh**

Our investment proposal will introduce an opex step change totalling $24.2m (real FY24) over RCP 24-29. This step change is due to investment in Low Voltage Visibility and Analytics (LVVA) and accelerating smart meter rollouts for Hot Water Solar Soaking (Off Peak +).

Our DER integration plan prioritises customer and operational solutions prior to considering traditional augmentation, underpinned by investments in the foundational systems required to enable this. The Plan below sets out our 4 key areas of focus and investment:

1. **Enabling Systems**
2. **Tariff Reform and Demand Flexibility**
3. **Network Capability and Operational Optimisation**
4. **DSO Operations**

The project level breakdown with their associated net present value is shown below in Table 2 and illustrates the alignment to these 4 focus areas of our strategy.

Table 2 – Proposed DER Integration projects overview expressed in FY23 present values

Project	Investment Type	Costs (PV FY23)	Economic Benefits (PV FY23)	NPV (FY23)	Alignment to Focus Areas
LV Visibility, Analytics & DVMS	Opex	$15.9 m	$29.9 m	$14.0 m	
DTX Monitoring	Capex	$11.0 m	$15.0 m	$3.9 m	
Transformer Tapping & Phase Balancing	Opex	$4.3 m	$7.3 m	$3.1 m	
Off Peak + (Solar Soak)	Capex	$5.7 m	$6.5 m	$.8 m	
LV Augmentation	Capex	$29.0 m	$60.9 m	$31.9 m	
Flexible Exports (Dynamic Operating Envelopes)	ICT Capex	$4.5 m	$6.6 m	$2.1 m	
Total		**$70.3 m**	**$126.2 m**	**$55.9 m**	

*Total costing also includes customer complaints call investigation opex ($2m) not listed as an investment category.

These investments will benefit customers in several ways. They will:

- allow for hosting more DER which will put downward pressure on wholesale prices for all customers and reduce customer carbon footprints.
- make it easier for customers to participate in voluntary demand response programs and/or earn incentives through tariffs.
- Improve our visibility of existing and emerging constraints so they can be resolved and so the network can be managed more dynamically to maximise value for customers.
- improve our ability to work with customers, aggregators and VPPs to coordinate and optimise flexible loads.
- improve the ability of non-DER customers to access and benefit from excess solar.
- increase resilience for customers in areas whereby local generation and DER resources can be utilised to reduce the frequency and duration of outages.

2. Context and Background

2.1 Purpose

This *DER Integration Strategy* has been developed to set a longer-term context and vision to guide and align DER integration investments in the Endeavour Energy network.

Specifically, it will:

- Provide a long-term DER penetration forecast developed from credible sources and contextualised to Endeavour Energy's network and customer base.
- Detail how tariff reform will be used to accommodate the forecast and reduce network investment.
- Review current and past investments into DER integration to track their effectiveness in delivering customer outcomes.
- Develop a portfolio of credible and industry leading options for better integrating DER and equitably managing and sharing network hosting capacity.
- Detail our plans to implement Dynamic Operating Envelopes as well as any relevant jurisdictional requirements, directives or priorities as identified by regulators, government, or market operator.

2.2 Our Customer Engagement Approach

Through adopting the "Better Resets" pathway, customers and stakeholders have been able to have truly informed conversations with us about the outcomes we are striving to achieve as the industry transforms, and what it could cost to deliver. Given so much of the energy transition will be driven by and for customers, we see one of the most important issues to capture is our customer's view on how we should be planning for the energy transition.

Our engagement plan focused on understanding the detailed preferences of customers and stakeholders with respect to key trade-offs relating to those aspects of our Preliminary Proposal that customers could genuinely influence. An overview of this engagement phase is shown below in Figure 1.

Figure 1 – Customer engagement phase 3 process

The Customer Panel has been a central feature of our engagement approach. Its purpose was to deeply engage with a broad and representative cross-section of residential and small business customers through an extended deliberative process. The Customer Panel's preferences were then shared with a broader group of stakeholders who participated in a series of Deep Dives. A more detailed explanation of this process is found in the draft proposal and its attached engagement reports.

The feedback we received aligned with a desire to enabling the energy transition and customer choice around DER, including that:

- Customers and stakeholders are keen to be involved in the transition to a low carbon economy and want Endeavour Energy to take steps to prepare for an accelerated transition, with customers considering further significant take-up of Solar Panels, Electric Vehicles (EVs) and Batteries.
- Customers aspired to the energy transition delivering a win-win outcome: a cleaner environment while also achieving personal savings through smarter, more efficient technologies and greater choice and control of their energy usage.
- There was therefore an expectation that Endeavour Energy increase its focus on technological innovation and implement smarter ways of serving customers and communities.
- Stakeholders were mindful of meeting customer expectations to generate and share their energy with minimal limitations on the uptake of DER to support a low carbon future and customer energy savings. Stakeholders were also concerned about the impact the transition to large scale renewable generation across NSW would have on electricity bills and the need to support the transition to DER in a fair and equitable manner for all customers

The detailed feedback collected during these deliberative forums has shaped our DER Integration Plan to deliver value aligned to the expectations of our customers as shown in section 5.1 of this document.

2.3 DER Vision

We aim to be a platform that enables the energy transition. We will enable our customers to flexibly use their DER to meet their own energy needs as well as to trade surplus energy into emerging DER markets. To do this we will advance our network operations to transition from a DNSP to a DSO role, playing an active role in facilitating and maximising two-way energy flows while maintaining network security and reliability. Through advanced network operations and targeted network investment we will economically maximise our network's DER hosting capacity aligned with our customers feedback and expectations.

2.4 Business Context

This DER Integration Strategy and DER Integration Business Case fits within the context of Endeavour Energy's overall Future Grid strategy.

The Future Grid Strategy seeks to outline our approaches to navigating and enabling the energy transition – success will be measured not only by ensuring electrical services can be maintained or new services made available, but that electricity becomes more affordable, and can be delivered with a lower environmental impact to all customers.

The purpose of the Future Grid Strategy is to:

- Define the emerging challenges and opportunities for customers generated by the energy transition.
- Outline Endeavour Energy's approach to investment in our Future Grid programs.
- Ensure investment line-of-sight between the long-term interests of customers, Endeavour Energy's corporate strategy and Network Business Strategy and other major sector reform initiatives.

2.5 Regulatory Context

2.5.1 Post 2025 Future Market Program

The detailed technical, regulatory activities that will be delivered over the next three years are set out in the Energy Security Board (ESB) DER Implementation Plan [1]. These are being led by the market bodies and agencies who are best placed to progress each reform. They will work through the existing National Electricity Market review, rule, and other change processes.

2.5.2 ESB DER Implementation Plan

The DER Implementation Plan sets out reform activities necessary to support the effective integration of DER and flexible demand. These reforms address a range of technical, regulatory and market issues over a three-year period. Reforms are intended to leverage technology and data, improve access and efficiency, enhance market participation, and strengthen customer protections and engagement.

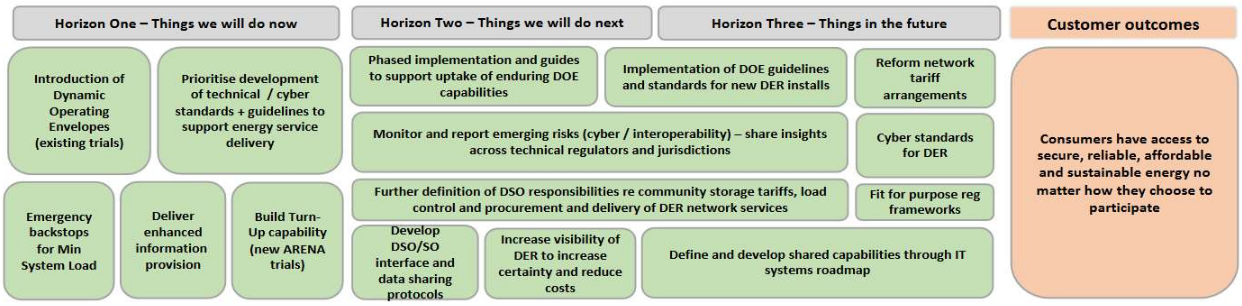

Figure 2 – ESB DER implementation plan over three-year horizon. Sourced from [1]

The ESB states the aim of these ‘Critical path’ actions for DER Integration is to, by 2025:

- enable DER owners to sell DER services into wholesale energy, ESS and network services markets
- for DER to not cause any technical system or network operation challenges
- to have integrated transmission and distribution planning

2.5.3 AEMC Access and Pricing

A major milestone for the energy transition was the AEMC Access Pricing and Incentive arrangements for DER in 2021. Previously the rules were written in the context of energy services delivered as a one-directional flow. This rule change was significant as it allows networks to recognise our role in enabling customer exports and multidirectional flow. In the context of our network planning and the upcoming regulatory submission, this is significant as it recognises that network investments may be needed to enable DER participation and the emergence of a new expenditure category.

Furthermore, the rules require the AER to develop and consult on a customer export curtailment value (CECV) methodology and publish CECVs annually. The AER currently has developed a draft CECV

2.5.4 AER’s Draft DER Integration Guidance Note

In July 2021 the AER released their draft DER integration expenditure guidance note. This Strategy and Business case has been developed with due consideration to this guidance note including the content expected in a Strategy as well as the Value of Distributed Energy Resources (VaDER) framework within which to consider DER Integration business cases.

3. Our Current DER Landscape

3.1 Current DER Penetrations

3.1.1 Solar PV

At present, 23% of Endeavour Energy's residential customers have solar PV systems with a cumulative capacity of 1GW. This corresponds to 27% of Endeavour Energy's summer 2021/22 recorded peak network demand of 3.7GW. It should be noted that in addition to this, there is a further 200MW of commercial and industrial sized solar generation within the Endeavour Energy network.

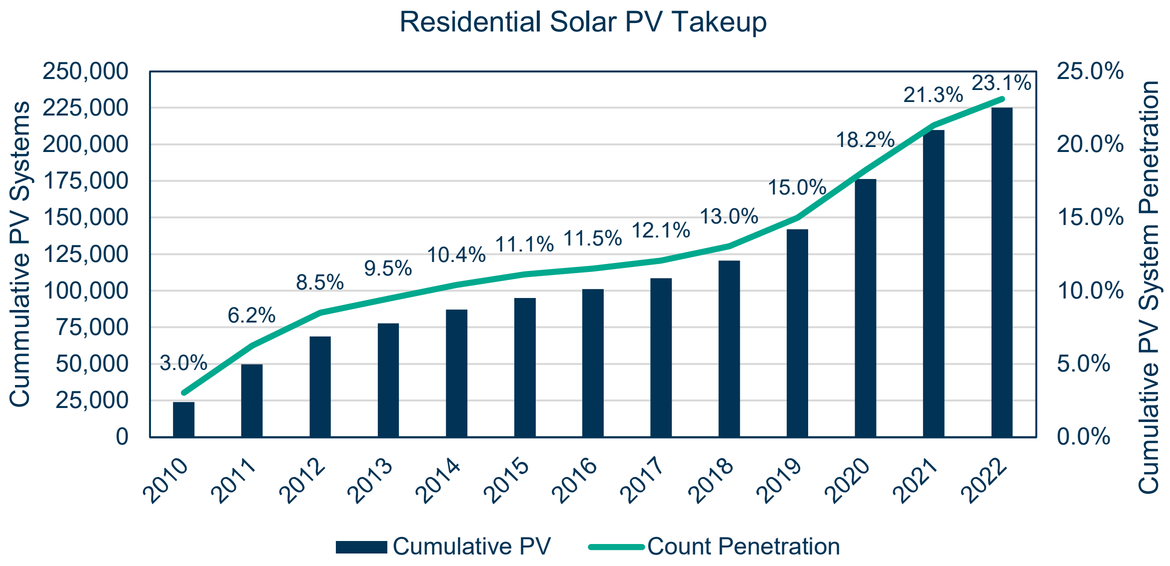

Figure 3 – Cumulative residential solar penetration trend

Continued declining PV system costs as well as robust solar feed in tariffs (FITs) have meant that customers are investing in larger systems over time as shown below in Figure 4. Between 2007 to 2022 the average residential solar system size steadily increased from 2.9kW to 7.2 kW. If the trend in system size take-up was to continue then the average system size would rise to 9kW by 2029, significantly well above current static export limits.

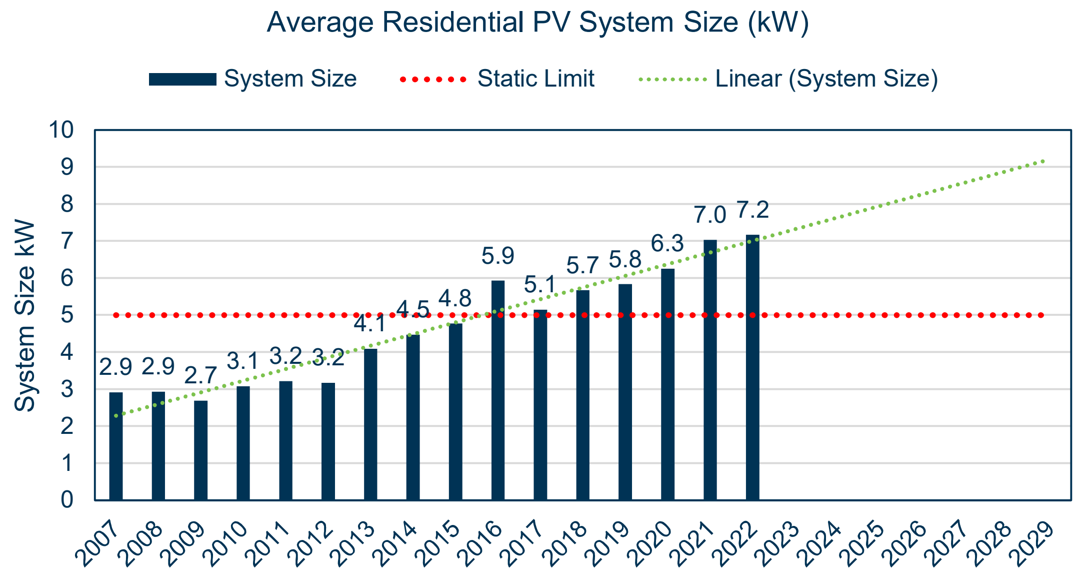

Figure 4 – Average residential solar system size trend

These solar trends are expected to continue to increase. Furthermore, with a forecasted uplift in EV uptake, it is possible that this spurs a further acceleration in PV system uptake and sizing as more households elect to use renewable sources to charge their car, unlocking economic and environmental benefits in doing so.

Within a commercial context, 14% of Endeavour Energy's customers have solar PV systems with a cumulative capacity of over 200MW. Endeavour has seen significant interest towards commercial solar with major companies looking to install rooftop solar on their buildings in the order of 1-10MW in size. Wester Sydney Airport is just one example of this with the proposed solar farm expected to reach up to 50MW. Multiple major developers within the Aerotropolis are already engaging with us to explore 100% solar communities across 5 of the new Zone Substations planned for construction.

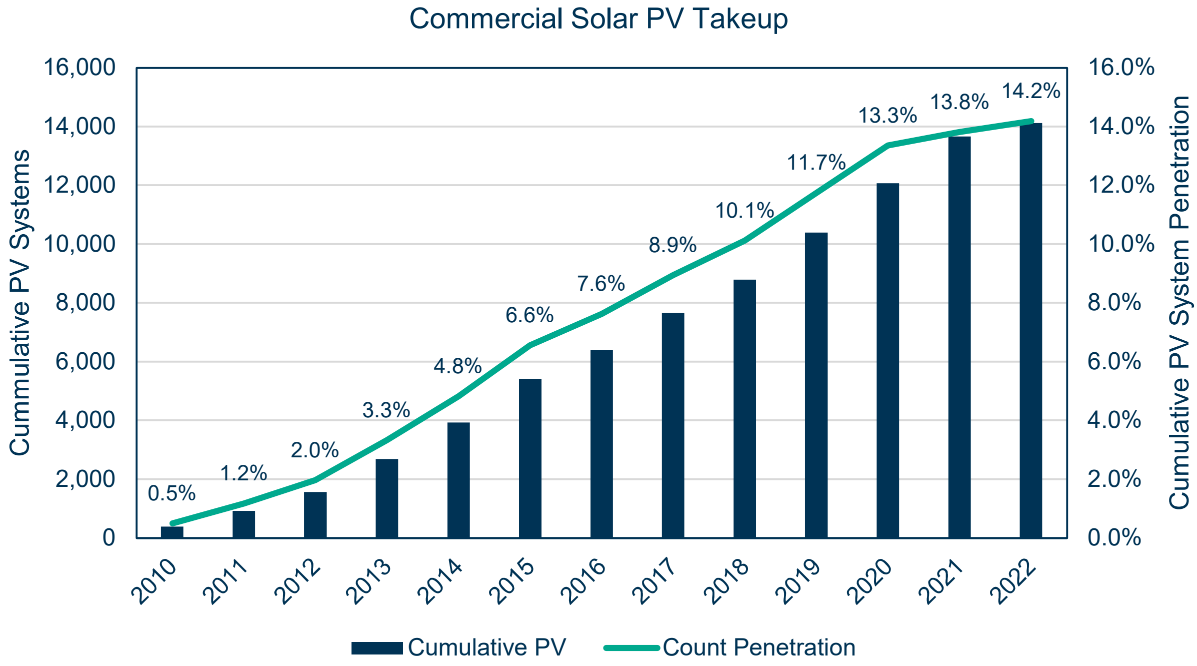

Figure 5 – Cumulative commercial solar penetration trend

This combination of residential and commercial/industrial solar has immense potential to support the energy transition, however it requires network investment in to enable the full benefits.

3.1.2 Battery

Residential battery system take-up has been lower than expected with relative battery system cost declines not matching that of solar PV systems. As such, for most customers investment in solar with a battery system has a significantly longer payback period than a solar system alone.

We have only recently begun the collection of Battery System applications data for behind the meter battery systems. This makes it difficult to determine the growing penetration on the network. To assess the current penetration of battery systems we have used two methods:

- smart meter data analytics through the Gridsight platform we have determined that as of June 2022, 0.5% of solar customers have a battery system.
- the Clean Energy Regulator's battery dataset for NSW and applied a pro rata representative of Endeavour Energy's share of NSW electricity customers. Further, we have adjusted the 2022 numbers to pro rata for year-end 2022.

There is strong alignment between these two data sources for actual battery take-up as shown below in Figure 6.

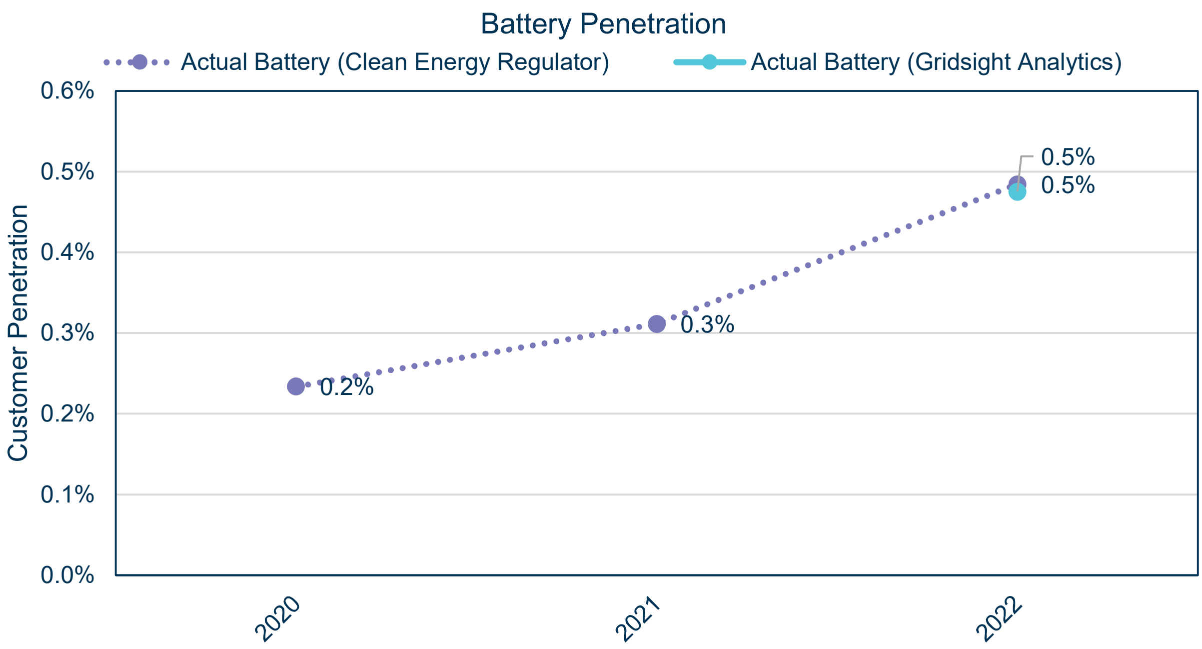

Figure 6 – Battery penetration Clean Energy Regulator vs smart meter detected batteries

3.1.3 Electric Vehicles

Although lagging the global market, EV uptake in Australia has been steadily increasing over the last few years with 2021 figures showing a 3x increase in sales compared to 2020. So far in 2022, EV sales are tracking at a similar rate as in 2021.

Like batteries, we have only recently begun the collection of EV applications data for behind the meter EV chargers. We estimate that currently we expect that just below 2000 of our customers currently own a plug in EV. This is based on two estimation methods:

- According to NSW registration data there is approximately 1821 EVs registered in the Endeavour Energy franchise area in 2021
- Through our LV Visibility and Analytics trial, we have so far detected around 90 customers with Level 2 chargers based on a sample size of 50,000 smart meters. This translates to an extrapolated 1900 level 2 chargers if scaled across the current network customer base.

3.2 Existing Challenges

3.2.1 Customer Call Trends

The rapid uptake of solar PV and subsequent export driven reverse power flows has steadily reflected in increasing rates of customer calls related to the performance of their DER systems, demonstrated in Figure 7. Typically, this relates to DER system curtailment or tripping. Whilst not all cases are due to network related power quality, all calls are investigated by first response crews, and where necessary, power quality technicians.

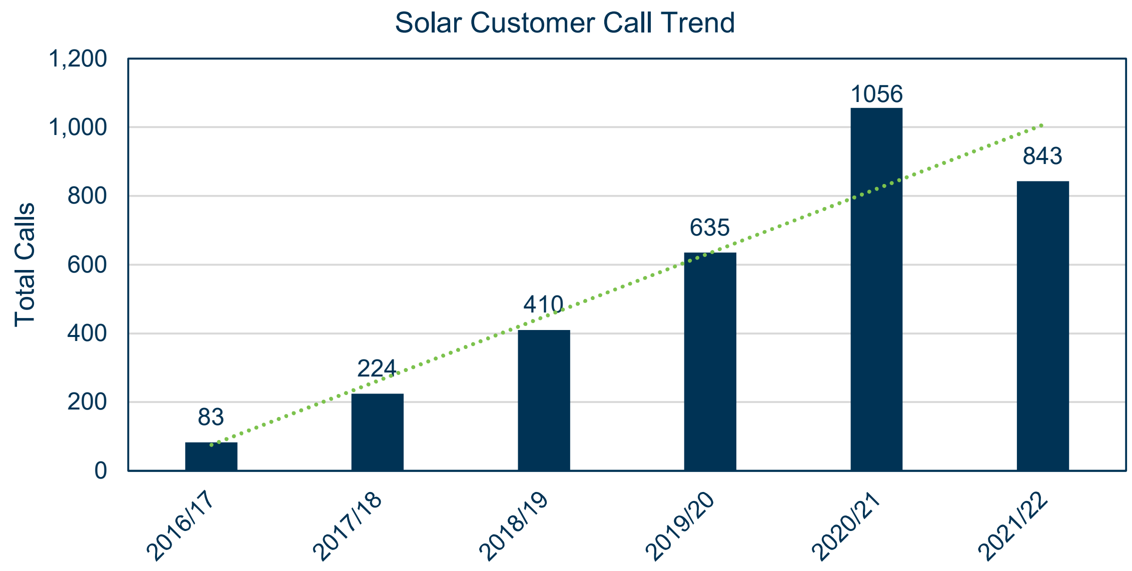

Figure 7 – Solar customer calls

It should be noted that the drop-off in customer calls in FY22 is due to continued reactive Distribution transformer tap changing, commencing daytime voltage reduction scheme at two thirds of our zone substations (discussed in section 3.3.3), as well as generally poorer than average solar isolation due to persistent *La Nina* conditions bringing higher than average cloud and rainfall. The volume of customer calls places significant operational pressure to respond to customers in a timely manner.

It should also be noted that customer calls are a subset of a broader issue – and that is the curtailment of solar exports. To enable the energy transition, a DSO operates a network that can dynamically respond to the variable nature of DER such that curtailment is kept to a bare minimum.

3.2.2 Power Quality Compliance

Through recent access to a representative sample of power quality data from smart meters at some 4% of customer sites we have assessed our current 2022 compliance to AS61000.3.100 as shown in Figure 8.

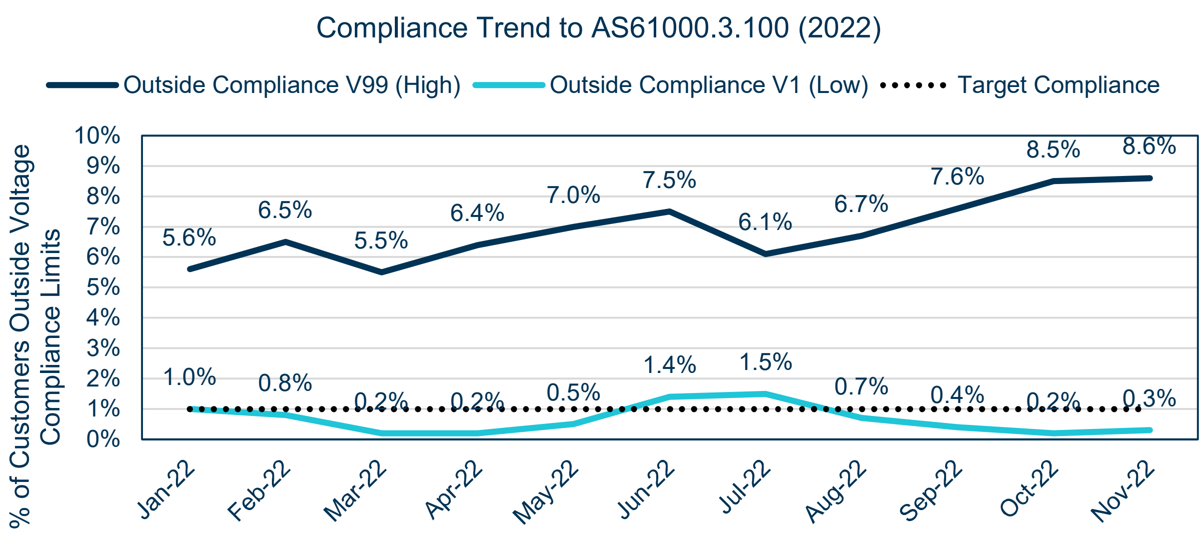

Figure 8 – Voltage compliance trend

It is evident that while taking many actions to improve voltage compliance to V99 (253V) limits, Endeavour Energy still has a sizeable portion of customers who experience voltage levels above limits, constraining hosting capacity. Endeavour Energy is currently generally compliant to V1% (216V) limits.

In NSW, IPART has in recent years commenced tracking network voltage excursions outside of emergency limits under AS6100.3.100. While these limits are broader than the compliance limits, it indicates an increasing jurisdictional interest in quality of supply maintenance by networks which will be stressed by higher penetrations of DER exports.

3.2.3 Inverter Standards and Power Quality Response Modes

The revision of AS4777 in 2015 saw the mandatory introduction of inverter power quality response modes in addition to inverter trip limits, with volt-watt mode mandatory and volt-var mode optional. Endeavour Energy communicated to installers that we required the application of volt-var mode where this function was available in the inverter, however compliance to this directive has been poor due to the non-standardisation of this requirement nationally, poor knowledge of installers in configuring such modes and a diversity of availability of these modes in inverters.

The 2020 revision of AS4777 requires mandatory application of both volt-watt and volt-var power quality response modes. This nationally applicable requirement is expected to vastly improve compliance to the application of volt-var response modes through a consistent approach to settings.

PQ response modes protect neighbouring customer equipment from overvoltage and potential inefficient equipment damage that may result. Inverter volt-var operation can significantly assist in improving hosting capacity and therefore reduce curtailment particularly in open wire overhead networks.

Recently we have been able to analyse compliance of inverters aligning to the AS4777 response modes on a sample of approximately 21,000 solar installations as shown in Table 3. It is however noted that we can only identify compliance with these modes where PQ response modes have been activated such as when voltage levels are out of bounds. As such, for networks with good power quality, we are unable to identify inverters PQ settings as they have not been activated.

Table 3 – Gridsight analytics detected AS4777 response mode compliance

Relevant AS4777 Version	Compliance		
	Volt-Watt	Volt-Var	Overvoltage Trip
2015	99%	1%	73%
2020	86%	47%	65%

This analysis shows that:

- Volt-watt compliance is high across both standards.
- Volt-var compliance has improved significantly under the 2020 standard.
- Overvoltage disconnect compliance is generally lower than volt-watt. This may be due to installers incorrectly configuring the over-voltage trip setting.

3.2.4 DER Connection Rules

Connection Limits

At present, we automatically approve the connection of small-scale solar systems with a combined inverter capacity of 10kW single phase and 30kW three phase subject to static export limits. Larger commercial solar systems are processed separately and are subject to technical review.

Static Export Limits

Since 2015 we have applied static export limits of 5kW single phase and 30kW three phase for small scale solar systems. This was informed by broader industry practice and considering that the voltage rise effect of a 5kW single phase system is the same as a balanced 30kW three phase system due to the influence of the neutral conductor in a single-phase installation.

Similar to the AS4777 compliance checks, we reviewed compliance with the 5kW export limit for invertors exceeding this size. Unfortunately, the compliance rate is again low as shown in Table 4.

Table 4 – Gridsight analytics detected static export limit compliance

Export Limit Compliance	
5kW Static Export Limit	**30kW Static Export Limit**
22%	No practical limitations on residential 3ph systems. Analytics on commercial systems yet to be undertaken.

Zero Export Limits

We do not currently apply zero export limits on small scale solar systems up to 30kW. Systems can export to our standard static export limits unless curtailed otherwise via power quality response modes. Zero static export limits are not applied on commercial solar systems, unless self-selected by the customer.

3.2.5 Existing Cost Reflective Tariff Adoption

Endeavour Energy has had a demand-based cost reflective (CR) tariff since 2020. This tariff has been the default tariff assigned to all new customers.

As of April 2022:

- 62,000 residential customers were on cost-reflective tariffs. This represents 6% of total residential customers. Only 29% of residential customers have interval meters capable of supporting a CR tariff. The take-up of CR tariffs for residential customers with interval meters is a disappointing level of 22%.
- 6,600 business customers were on cost-reflective tariffs. This represents 8% of total business customers. Only 24% of business customers have interval meters capable of supporting a CR tariff. The take-up of CR tariffs for business customers with interval meters is 33%.

It is disappointing to observe that there is little evidence that retailers are passing our price signals on to customers at this stage, indicating that the expected impact in end customer changed behaviour is low. Thus, we have little information on customer response behaviour to network tariff signals that can inform the design of new tariffs in the future.

3.3 Current Regulatory Cycle DER Investments

DER integration investments in the current regulatory cycle have been incremental but foundational for our future in the energy transition. The focus has been on:

- Enabling Systems – The no regrets foundational steps that will be required to deliver future initiatives
- Pilots – Smaller scale trials to test new technology to inform best scaling approach
- BAU/Rollouts – Business as usual ready projects to rollout across the network

The specific actions and projects undertaken or in progress are summarised in Figure 9 below, including their status.

Category	Project	Description	Status
Enabling Systems	DER Register	Internal DER Register database developed capturing customer and DER metadata	
	Timeseries Historian	New database infrastructure being commissioned to expand timeseries data capabilities	
	RTU upgrades (DVMS)	70% of Zone Substations now ready for dynamic voltage management setpoints	
Pilots	Distribution Transformer Monitors	Stage 1 rollout currently 10% complete targeting 1800 monitors	
	LV Visibility and Analytics Platforms	Data for 50,000 meter points being collected and 2 analytics platforms in trial	
	New LV Network Technology Solutions	Trial of LV STATCOMS completed and Network Support Batteries commencing	
	Off Peak Plus Pilot	Dynamic hot water control system through smart meters successfully deployed at Albion Park	
BAU/ Rollouts	Distribution Transformer Tap Change Program	38% of distribution transformer taps have now been changed to the optimal taps	

Figure 9 – RCP 19-24 DER Integration projects, actions & initiatives

A detailed explanation of each of these initiatives can be found below in the remainder of section 3.3.

3.3.1 DER Register

A DER register database has been developed that integrates with our customer connections database (solar connections portal), AEMO's DER register API, as well as other corporate and network data systems.

This register has enabled us to track solar PV take up in a granular fashion at the customer, distribution transformer, zone substation and whole of network level. The register also combines tariff data, metering data and other customer DER such as controllable hot water systems with works underway for inclusion of EV and home batteries.

Figure 10 – DER Register reporting dashboard

This register is a foundational input into hosting capacity modelling, demand forecasting as well as translating AEMO's ISP forecasts to our network hierarchy.

3.3.2 Timeseries Historian

The transition from a DSNP to a DSO will bring with it a future of increasing data. More granular network visibility and monitoring combined with a shift in market data transitioning from 30 minute to 5 minute intervals has required the design and commissioning of new infrastructure to manage and store this timeseries data.

We are investing in a new historian database that will be the enabler of systems such as ADMS, and LV analytics platforms to build upon and utilise. This system is a foundational step in enabling the energy transition and is due to be fully productionised by the end of 2023.

3.3.3 RTU Upgrades (DVMS)

Zones Substations across our network have traditionally managed the outgoing HV feeder (secondary) voltages based on a static nominal set point. The continuous increase in rooftop PV creates higher customer voltages during daylight hours and the forecasted increase in electric vehicles will pull voltages lower during night hours from increased loading. This widening spread of voltages throughout the day requires our voltage set points to become more dynamic.

A dynamic voltage management system (DVMS) is on our future roadmap as explained in section 5.5.3 however it will require a foundational upgrade of the remote terminal units (RTU) at all zone substations to allow for dynamic setpoints to be feasible.

A program is underway to upgrade this equipment and is currently 70% completed at zone substations across the network. For the sites that have been completed, we are currently using a daylight reduced setpoint to alleviate solar penetration as an interim step before DVMS deployment. This initiative has already helped reduce customer voltage complaints at these locations.

3.3.4 LV Visibility and Analytics Platforms

As with many distribution networks, Endeavour Energy has limited visibility of the LV network. There are currently 330,000 smart meters installed in Endeavour Energy's network, representing approximately 30% of customers.

Under the Power of Choice framework, distribution networks negotiate access to power quality data from smart meters with retailers and/or metering providers (MP) and meter data providers (MDP). We commenced data access trials in 2019 with the initial purchase of power quality data from 1,000 meters. Over the last 3 years we have now expanded this to 50,000 meters.

Analytics Platforms

To maximise value from this LV visibility data, we have engaged with two LV analytics platform providers to better understand the range of benefits achievable from smart meter data as well as other sources of visibility data such as customer DER and Distribution Transformer Monitors.

A list of priority use cases has been developed below in Table 5 covering the 2 different ways that data is delivered to and processed by these platforms:

1. Delayed delivery model with data delivered 24hr after the time of measurement.
2. Real time delivery model with data delivered 5-15 mins after the time of measurement.

Table 5 – LV Visibility and Analytics trials use cases, progress, and learnings

Target Use Cases	Progress	Comments
Delayed Applications (based on 6-24hr data delivery and 5 min intervals)		
Loss of Neutral Detection (Safety)	Demonstrated	Within the first year of using this data we have detected and repaired over 55 cases of broken neutrals and broken phase conductors both at the customer service and network mains level. This is already improving customer safety significantly and is the single biggest opportunity to improve public safety shocks risk from failing service and LV mains.
PQ Compliance Assessment to Avoid Truck Rolls (Efficiency)	Demonstrated	We are now first utilising the available LV visibility data and the automated standards compliance assessment reports which is avoiding 30-40% of truck rolls for compliance monitoring purposes. This has allowed us to maintain existing staffing levels whilst experiencing a growing number of DER related customer calls which is expected to continue.
Inverter Compliance to AS4777 Response Mode Static Export Limits	Demonstrated	We are using analytics to validate which DER have inverter settings compliant to AS4777 (2015 and 2020 versions). Specifically, we have demonstrated being able to validate if inverters have volt-watt, volt-var, voltage disconnection trip and static export limit compliance. This may assist future programs to retrospectively improve compliance.
PV Size Validation	Demonstrated	Analytics have been developed to validate the size of over 22,000 PV systems so far. The absolute average per site error in our records is 1.7kW per system, equating to a 25% error per system on average. compared to our DER register records dramatically improving locational PV size accuracy.

Target Use Cases	Progress	Comments
Battery Detection	Demonstrated	A total of 513 batteries have been detected, providing a current penetration per solar customer of 0.5%
EV Detection	Demonstrated	Level 2 EV charging detection has been demonstrated and proven
Curtailment Calculation	Demonstrated	Daily, weekly and monthly calculated curtailment for 22,000 PV systems is being provided split by cause (volt-var, volt-watt and voltage trip). This provides an actual measured curtailment comparison to modelling and insights into which modes lead to the greatest curtailment.
Customer Phase Detection	Demonstrated	Detected customer phasing across some 50,000 customers. Accuracy has been validated through sample field-based checks (GPS phasing) demonstrating high accuracy.
Customer to Transformer Connectivity Validation	Demonstrated	Over 35 instances of GIS connectivity errors have been detected (i.e., where a customer is connected to adjacent transformer LV network rather than the GIS recorded transformer). A number have been validated through field inspection or desktop (streetview) demonstrating high accuracy.
Optimal Tap Setting & Phase Balancing	Future	Expected early 2023
Transformer Load Estimation	In Progress	Expected late 2022
Historic State Estimation	Future	Expected to be trialled early 2023
Customer Load Profile segmentation	In Progress	The clustering of load profile characteristics and the associated metadata across all customers in the network to better understand usage patterns, tariff designs, and non-network solutions to demand management.
Conservation Voltage Reduction	Partially Demonstrated	Testing as part of system security support (RERT). Tests demonstrated CVR factors of 0.8 or higher in winter and 0.5-0.6 in summer. This demonstrates that there are power and energy savings from customer appliances associated with global voltage reduction.
Real Time Applications (based on 5-15 min data delivery and 5 min intervals)		
Dynamic Voltage Management	In Progress	Expected to be trialled late 2022.
Real Time Outage Mapping	In Progress	Expected to be demonstrated late 2022.
Dynamic Operating Envelopes	Future	Expected to be trialled early 2023

It is evident that LV visibility and analytics has great potential and a broad range of benefits. We are using the learnings of these trials to inform the investment business case for broader DER focussed LV visibility access and associated analytics requirements discussed in section 5.3.1. of this document.

3.3.5 Distribution Transformer Monitoring

To supplement our broader based LV visibility from smart metering, we have commenced a small-scale targeted rollout of 1800 cost-effective Distribution Transformer Monitors across our network. Historically we have not invested in distribution transformer monitoring in a meaningful way. This initial deployment represents coverage of some 6% of our distribution transformers. The deployment was highly targeted towards our highest solar penetration Distribution Transformers (greater than 50%) as well as overloaded distribution transformers to confirm transformer replacement requirements, avoiding temporary monitoring as well as avoiding the risk of unnecessary transformer replacements.

These data points are providing a low cost and real time view of the network and enable dynamic responses to be implemented to optimise the network. It is also providing early learnings of the benefits of blended visibility from transformer monitoring in combination with smart meter visibility (given the limitations and access costs associated).

3.3.6 New LV Network Technology Solutions

Endeavour Energy has an established Power Quality Compliance capital program which addresses compliance to AS61000.3.100 and other relevant standard limits. These programs are reactive programs rather than proactive. The programs primarily address compliance only where customers have initiated a complaints process with Endeavour Energy, and we have determined the network to be out of compliance.

Traditionally these investments include transformer uprates, additional distribution transformers to split LV networks, LV conductor amplification and LV network re configuration (establishing LV ties and open points). In recent years most of these reactive investments have targeted addressing overvoltage complaints and as such has strong alignment to DER integration.

We have also invested in testing new network technology solutions that have the potential to offer lower cost or greater value network improvement compared to traditional network augmentation.

- LV Static Compensators (STATCOMs) – STATCOMs provide automated volt-var compensation and are a highly effective solution on longer open wire overhead networks. We have deployed 12 LV STATCOMs to date. This technology is now proven and being utilised as an option for business-as-usual consideration in comparison to traditional augmentation approaches.
- Community Batteries – We are currently running a community battery trial funded under DMIA which seeks to understand the role of community batteries in addressing network constraints such as local solar hosting limits due to voltage while also delivering other network and system support benefits (such as relieving higher level capacity constraints). Both Pole Mount and Ground Mount solutions are being tested. The learnings from this program are expected to inform the role of community batteries in addressing solar hosting constraints (where economic) as well as co-investment models for such assets for both network, customer, and market benefits.

3.3.7 Off Peak Plus Pilot

In 2021 we launched our Off Peak Plus pilot project, which was a collaboration between a metering provider and several retailers to proactively transition off peak hot water customers in the Albion Park Zone Substation supply area to smart meters.

Endeavour Energy provided a financial incentive to the meter provider / retailers to expedite the bulk meter exchange (under the DMIS framework) on the basis that it avoided network investment in a replacement load control system as well as enabled additional benefits such as hot water solar soaking and improved network visibility.

This project transitioned hot water control from a network owned ripple control system to the smart meter. The ripple control system is used to turn on/off all units connected to a zone substation together as a batch with the same time schedule used for all.

Smart meter control allows for more flexible control of the heating times at the individual customer level by sending control signals direct to each meter through the meter providers remote API control interface. Both the network and retailer have access to control each meter, allowing both network management and retailer delivered market services (allowing for new customer offers).

The Off Peak Plus program provides tremendous benefits to customers by soaking up excess solar energy during the day, providing a discount tariff. This initiative is scalable to other services such as EV charging and provides Endeavour Energy with smart meter information to help guide future investment.

3.3.8 Distribution Transformer Tap Change Program

Endeavour Energy has some 33,000 distribution transformers. Historically, distribution transformer tap settings have been biased to conservatively avoid undervoltage conditions at customer equipment due to customer challenges faced during the 1990s and 2000s with regards to load growth and air conditioning. A significant proportion of the existing transformer fleet were tapped based on prior voltage standards with a nominal range of 240V+8%-6% (or 225V to 254V). The current Australian voltage standard has an allowable range of 230V+10%-6% (or 216V-253V) which allows for additional flexibility to lower LV voltages. Generally, this means that most distribution transformers are not currently tapped to their optimal position to enable improved solar hosting and voltage compliance.

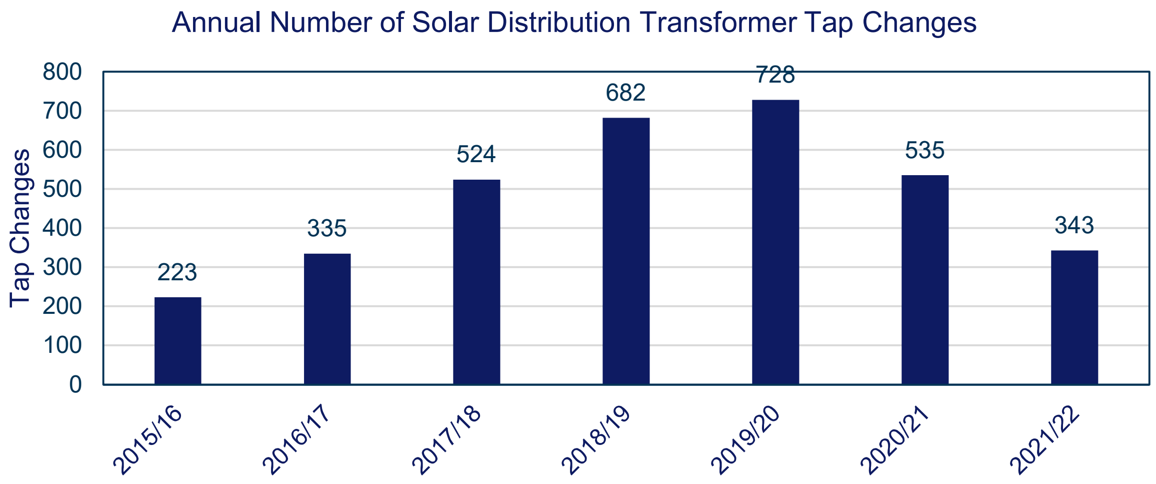

Figure 11 – Trend of distribution transformer tap changes

Over the last 7 years we have had an operational program to optimise the tap position by physically going to site and moving the set point. Currently 38% of transformers are tapped to their expected optimal tap setting, with some 62% not yet on their optimal tap. Some 7% of all transformers cannot be tapped down (optimised) due to not having buck taps available (legacy specification transformers) and will remain unoptimised. In these cases, we need to consider the justification for early tank replacements (complete replacement of transformer tank and associated active parts).

Our tap change program across 2020 and 2021 were heavily impacted by covid as well as flood conditions. It is expected that in FY23 onwards the number of tap changes will be similar to 2018-2019 levels.

3.3.9 Current Regulatory Expenditure Summary

A summary of our current regulatory period DER related expenditure is provided below in Figure 12 and

Table *6*.

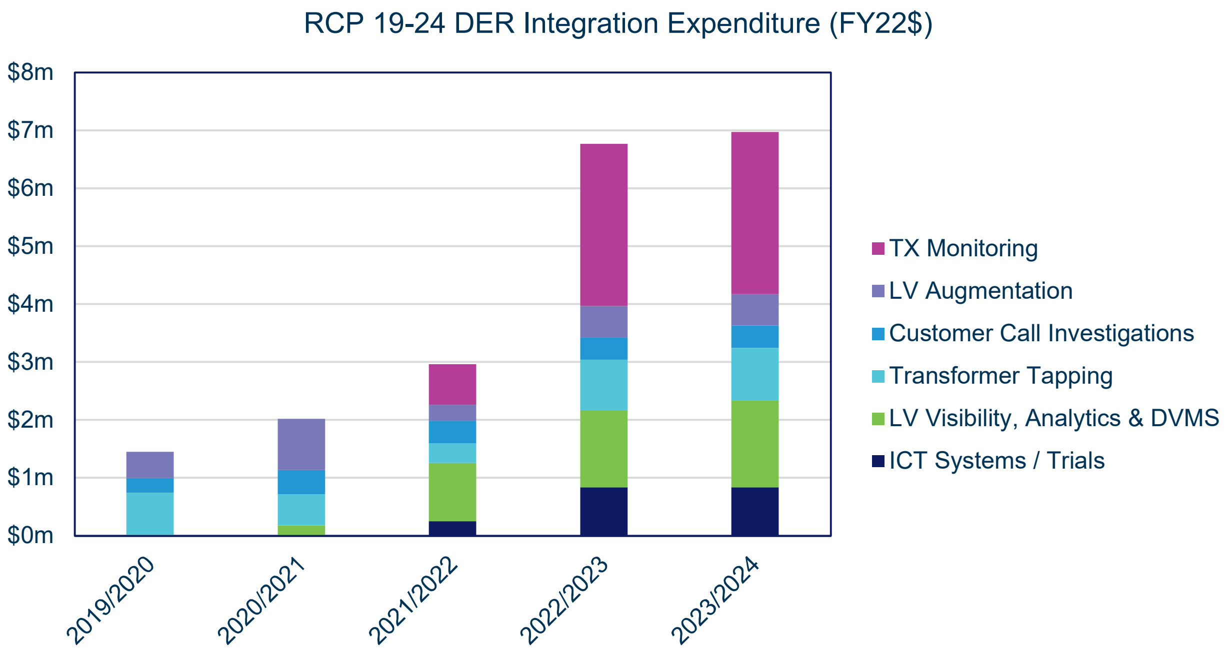

Figure 12 – RCP 19-24 DER Integration expenditure ($ nominal)

Table 6 – RCP 19-24 DER related expenditure

Investment Category	FY20 (N)	FY21 (N)	FY22 (N)	FY23 (N) * projected	FY24 (N) * projected	Total (RCP19-24)
Opex	$.98 m	$.96 m	$.73 m	$1.26 m	$1.30 m	**$5.2 m**
Network capex	$.47 m	$1.06 m	$1.98 m	$4.67 m	$4.83 m	**$13.0 m**
ICT capex	-	-	$.25 m	$.83 m	$.83 m	**$1.9 m**
Total	**$1.5 m**	**$2.0 m**	**$3.0 m**	**$6.8 m**	**$7.0 m**	**$20.2 m**

4. Looking Forward

4.1 DER Forecast

4.1.1 Our Customers Feedback

When our Customer Panel and reference group was asked "How do we modernise the network to meet emerging and future customer service expectations as technology and markets evolve?" We found:

- The majority (85%) of participants, including 100% of SMEs and almost four-in-five residential customers, want Endeavour Energy to modernise the network in preparation for either a rapid (very fast) or accelerated (fast) energy transition to accommodate future customer expectations as technology and markets evolve.
- The third who opted for a rapid transition including increased network capacity and extensive trials thought that what they described as the relatively small cost of $9 a year was outweighed by the potential benefits of lower bills, more choice and improved access to the network. They didn't want to risk constraints and potential blackouts and felt that urgent action is required now to tackle climate change.
- The majority (55%) who preferred an accelerated transition with limited trials and a smaller cost increase of $3 a year, saw this as a more prudent and pragmatic approach that balances innovation and bills, particularly in the face of higher cost-of-living pressures.

This feedback indicated Endeavour Energy should be preparing for an accelerated and rapid energy transition and we used the AEMO 2022 ISP scenarios as a way of mapping this posture.

4.1.2 Our Forecast Approach

The AEMO 2022 ISP has coverage of four primary scenarios to span plausible energy transformation futures, namely, Slow Change, Progressive Change, Step Change and Hydrogen Superpower.

The customer feedback supported a focus on the Step Change scenario which is described as a "rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action". However, we will also consider book end scenarios to this central case, namely a high and low case as follows:

- High Case: Hydrogen Superpower
- Central Case: Step Change
- Low Case: Progressive Change

Currently the AER's work on Customer Export Curtailment Value (CECV) only considers the Step Change scenario in it modelling and this further supports our use of this scenario as the central case.

To forecast the expected DER uptake on the Endeavour Energy Network, we engaged the National Institute of Economic and Industry Research (NIEIR) to translate AEMOs ISP 2022 DER forecast scenarios for NSW to Endeavour Energy's network out to 2040.

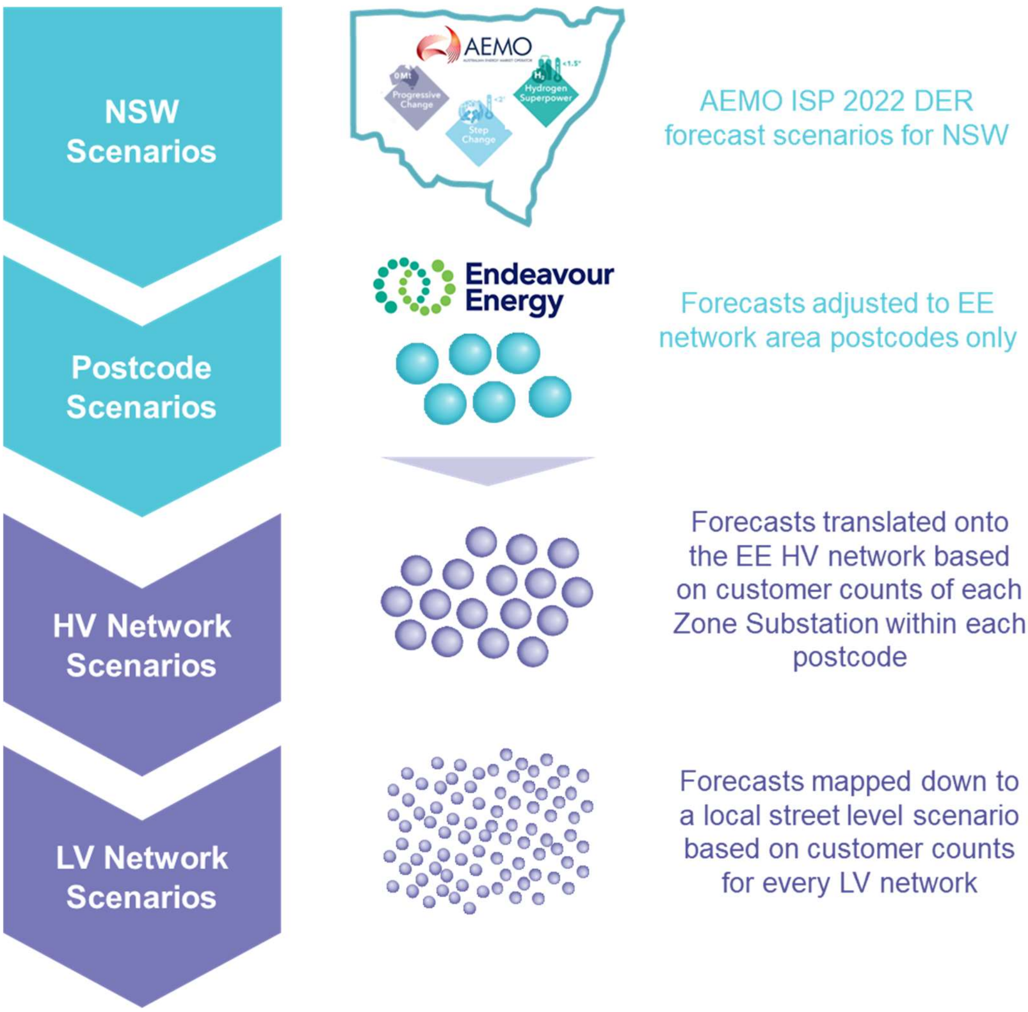

Figure 13 – Translation of AEMO ISP scenarios to Endeavour Network

At a high level this has been done as follows:

- **Solar PV**: NIEIR pro ratas AEMO's NSW solar PV forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future.
- **Batteries**: NIEIR pro ratas AEMO's NSW battery forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future to translate the battery forecast.
- **Electric Vehicles**: NIEIR's initial starting point is based on existing EV vehicle registrations mapped to Endeavour postcodes then translated to a share of the NSW total EV registrations. NIEIR then considered NSW postcode demographics data to determine what share of the forecast NSW EV growth is attributed to Endeavour postcodes. This was then mapped to our substations.

Using the step change customer DER forecast as a percentage of total customer connection points forecasted on the network, we have derived the expected penetration levels for each type of DER as shown below in Figure 14. PV penetration is expected to double by 2040 and EV growth becoming most significant during 2030-2040.

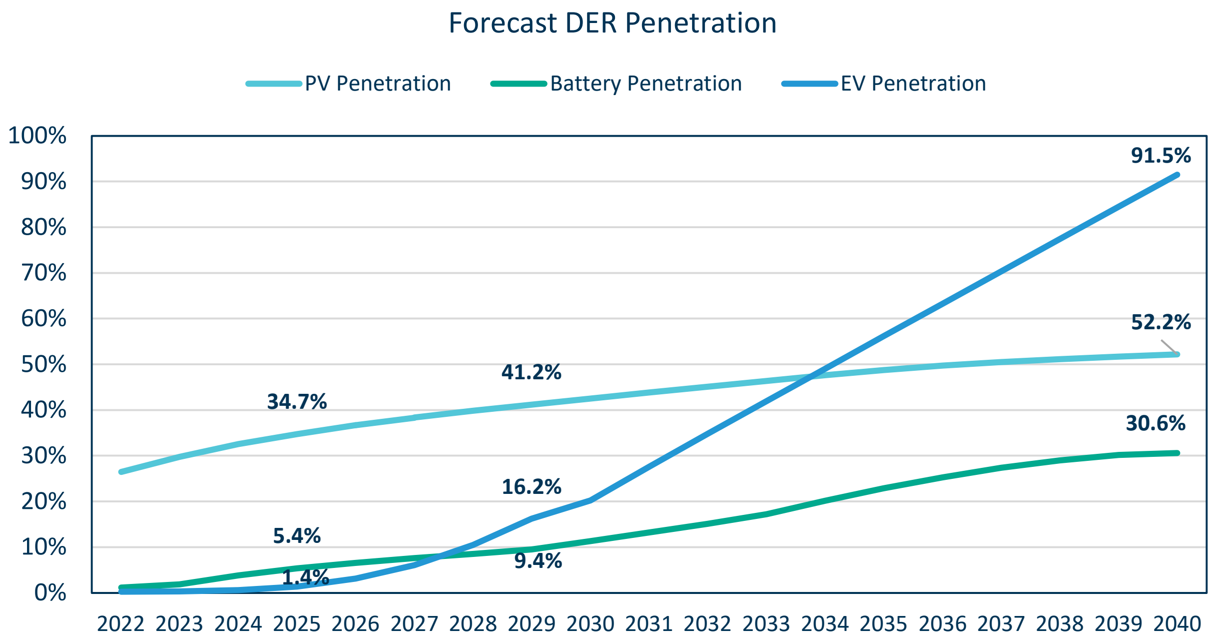

Figure 14 – Forecast DER Penetration

It should be noted that:

- EV penetration refers to connection point (customer penetration) rather than vehicle population penetration. As such the connection point / customer penetration of EVs can exceed 100% due to multi vehicle households.
- All penetration values have been normalised to Endeavour Energy's projected customer growth.

4.2 Hosting Capacity Analysis

4.2.1 Our Approach

There are multiple approaches to simulating and assessing DER hosting capacity, or inversely quantifying the impacts of unconstrained DER uptake on the network. The AER's DER Integration Guidance notes that hosting capacity can be "deterministic or probabilistic and can be undertaken using a range of modelling and analysis methods."

Endeavour Energy has developed a LV simulation tool in partnership with researchers at the University of Wollongong's Australian Power Quality and Reliability Centre. The tool takes advantage of the open-source electrical power flow engine OpenDSS to run time-series power flow simulations.

The hosting capacity analysis utilises the DER Forecast mentioned in the previous section and focuses on modelling residential customers.

A high-level overview of the simulation tool is shown below in Figure 15 and is broken down into 4 key stages:

1. DER Scenario Builder
2. LV Network Model
3. Load Flow Simulation
4. Options Modelling

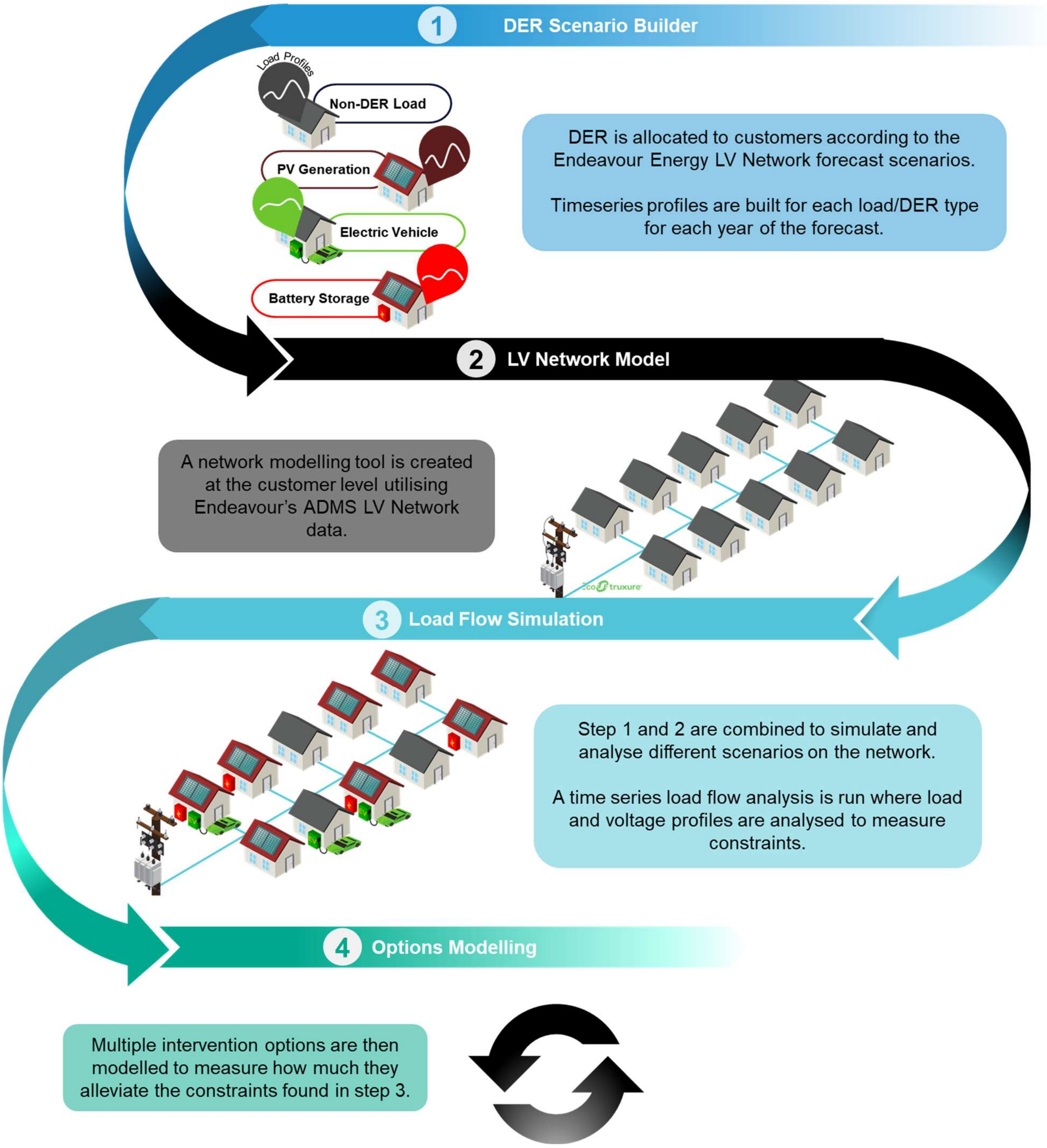

Figure 15 – LV DER Integration Simulation tool

A description of each of the 4 stages and the key features is provided below in the following sections.

A complete detailed explanation of this tool and the associated basis of preparation of the various data inputs is provided in Hosting Capacity Modelling Basis of Preparation (Attachment 1).

4.2.2 DER Scenario Builder

As discussed in Section 4.1, Endeavour is modelling a selection of AEMO's ISP scenarios, a central case (Step Change) along with two bookend cases (Progressive Change and Hydrogen Superpower). With each scenario, there are varying amounts of DER forecasted on the Endeavour Energy Network.

In this way, the DER Scenario Builder allocates PV systems, batteries and EVs to customers on the network so that the model aligns with the selected AEMO ISP Scenario. Within each year of the model, new DER is allocated accordingly.

PV Allocation

PV inverters are modelled explicitly in the system, so it is important to select the placement of these systems appropriately.

Existing PV customer locations are modelled accurately in the developed LV feeder model according to existing DER register data as described previously in section 3.3.1.

If the forecasted additional PV systems are assigned to the customers located at the far end of the feeder or closer to the distribution transformer this would result in extreme network conditions. It is required to assign the new PV systems forecasted each year to non-solar customers in a way that represents average network conditions. Therefore, we developed a LV feeder modelling algorithm to distribute the new PV systems evenly among the non-solar customers along each LV feeder.

Batteries and Electric Vehicles

Unlike PV inverters, battery storage systems and electric vehicles are not modelled explicitly in the software. For these DER types, the forecasted load profiles for each are combined with the baseline load profiles obtained from smart meters to create a new net profile that is given to all customers. The magnitude of the DER load that is added to the baseline is proportionate to the uptake forecast for each specific LV feeder.

Once these scenarios have been developed, a network model is required to host the load flow of these inputs.

4.2.3 LV Network Model

The simulation tool builds a network model in the OpenDSS powerflow software. The topology and line characteristics of the network has been modelled using exports of Endeavour Energy's ADMS and GIS LV network model data. Operational characteristics and transformer characteristics were obtained from the enterprise asset management systems and imported into the model.

Notably, within the network model, the AS4777 inverter power quality response modes such as volt-watt and volt-var are explicitly modelled in PV systems placed in the simulation.

Due to the size and complexity of the modelling, only downstream network from the distribution transformer is explicitly modelled in the load flow analysis. The exact HV network was not included in the load flow, rather approximation of network characteristics was used to account for upstream impacts. Overall, our modelling is expected to be conservative (under-estimate curtailment) and a complete list of these limitations can be found in

Table 7.

Table 7 – Network modelling limitations

Limitation	Effect of Limitation	Detail of Limitation
LV Network Only (Exclusion of HV Feeder Network in Models)	Underestimate voltage rise and curtailment	The models currently do not represent the aggregate coincident reverse power flows on the HV network which by extension underestimates voltage constraints.
Customer Service Mains	Underestimate voltage rise and curtailment	During the modelling process we discovered that ADMS has incorrect defaulting in customer service mains which leads to over 50% of customers having unrealistically low impedance services.
30-min time interval simulations vs 5 min	Underestimate peak solar output / peak mismatch between load and generation	Modelling at 30-min time intervals is likely to underestimate curtailment compared to 5-min intervals. Modelling at 5-min granularity is to be explored in the next phase of hosting capacity modelling for the preliminary submission.

4.2.4 Load Flow Simulation Model

Once the network model has been built to reflect the current network state, the parameters can then be modified to simulation future DER uptake on the network.

The DER scenarios and inputs discussed in section 4.2.2 are then used to modify the network model for each scenario, each year, out to the year 2040.

The load flow simulation produces 30-minute time series results at the customer and distribution transformer level. It should be noted modelling at 30-minute time intervals is likely to underestimate curtailment compared to 5-minute intervals however due to the computational strain of 5min load flows this modelling was completed using 30-minute data only.

The model seeks to understand the constraints on the network resulting from increasing residential DER uptake, namely:

- **DER Inverter Curtailment:** as per AS4777 trip settings and response modes
- **Distribution Transformer Capacity:** Transformer loading kW, maximum and minimum demand voltages
- **High-Voltage Feeder Capacity:** High voltage feeder loading kVA

The above constraints are measured for all input scenarios to understand the impacts on the network and to set a quantified baseline to explore interventions to alleviate these constraints.

4.2.5 Options Modelling

In response to the measured constraints, we have explored 7 intervention actions that build upon each other to alleviate the constraints resulting from increase DER integration in the simulations.

Section 5 of this document explains these 7 interventions in greater detail and our rationale behind each.

For these interventions to be accurately modelled, we built additional functionality into the simulation tool to:

1. modify load profiles to simulate tariff reforms, and
2. modify the scripts that build the OpenDSS model, changing parameters of equipment configurations, voltage setpoints and customer connection point phasing.

This additional functionality has created a robust simulation tool that can measure the improvements in curtailment as each intervention is added to the scenarios.

4.3 Future Grid Roadmap

As we look forward to what types of investments will be required to enable our customers future energy choices, we have developed a draft Future Grid roadmap as shown below in Figure 16. The roadmap considers the ESB's DER implementation plan, the AEMC's access and pricing reforms, stakeholder and customer feedback as well as an assessment of required capabilities to manage the network as a DSO while supporting the energy transition.

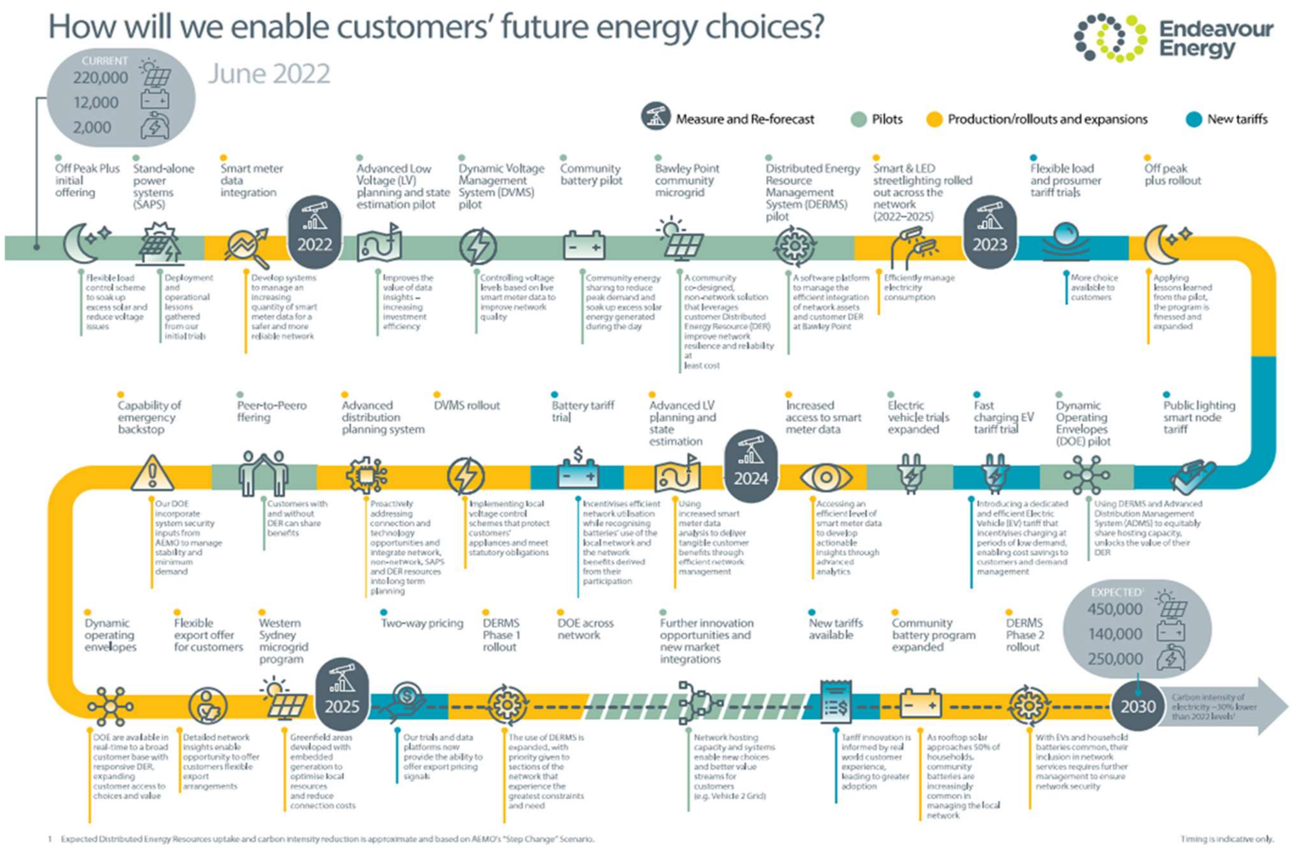

Figure 16 – Future Grid roadmap

This roadmap includes a portfolio of new DER integration investments and initiatives, beyond traditional operational actions and network investments. Our DER integration plan has been designed to be integrated with our broader future grid roadmap. The intervention actions we have developed serve to both alleviate the constraints on our network as simulated and be foundational steps in the delivery of our roadmap.

5. Our DER integration plan

5.1 Our Customers Feedback

During our engagement process (covered in section 2.2), our customer panel provided insightful feedback regarding the energy transition, specifically, their preferences for future services and DER grid access.

Their feedback has been instrumental in shaping our DER integration plan. The following sections highlight the key customer insights that have influenced our plans.

5.1.1 Future Service Priorities

At the beginning of our Customer Panel process, participants were shown a list of proposed future services we could provide and were asked to rate them in order of importance to them. Table 8 below shows the highest ranked services as voted by the panel.

The top priority service that customers want us to invest in is the enablement of Solar panel technology. Specifically, customers are calling for the future grid to be one that is prepared to accommodate solar for anyone wanting to connect and export to the grid. In this way, our DER integration plan has been developed with a strong focus on the optimisation of hosting capacity on the network.

The next two highest priority services; helping customers save money and greater reliability, both have linkages to LV network visibility and analytics which is a foundational element to DER integration. The ability to offer customers dynamic pricing to offset network constraints as well as quickly identifying loss of supply is aided through a more widespread use of smart meter data and the associated analytics platforms.

Table 8 – Customer Panel Future Services Preferences [2]

Overall ranking	Future services	Total voted in top 5 (n=)
1	**Solar panel technology:** Provide the necessary technology so that anyone who wants to use solar panels to generate their own electricity and export what they don't use into the grid can do so.	62
2	**Help customers save money:** Help customers save money if they choose to reduce their energy consumption during a heatwave so more equipment doesn't need to be built, helping keep prices down for everyone in the longer term.	52
3	**Reliability as the climate changes:** Invest in infrastructure and / or new technology so the current levels of reliability (number of blackouts and speed with which they are fixed) can be maintained as the climate changes (e.g., if there are more floods and fires).	48
4	**Electricity trading:** Provide households with an option to send any excess energy from their solar panels to a battery shared with neighbours so they can trade electricity with each other. This would also help make the grid more efficient and keep downwards pressure on bills.	41
5	**Help cut greenhouse gases:** Help cut greenhouse gases and set targets to do this by 2040 through investment in new technology.	40
6	**New ways of charging:** Introduce a new way of charging so that customers can save money by changing the time of day they consume electricity or export solar to match the changing supply and demand in the grid.	37
7	**Electric vehicles:** Ensure the grid is able to cope with the increased demand likely to come from an influx of electric vehicles.	32
8	**Fast-track the infrastructure needed to connect:** Fast-track electricity infrastructure like substations to connect new business and housing developments so our region can grow quickly rather than invest 'just in time'.	28
9	**Communication on disruptions:** Provide customers more accurate and timely information about unplanned and planned disruptions.	22
10	**Underground cables:** replace above ground wires with underground cables to reduce fire risk and improve public amenity (note that this would cost significantly more and often takes longer to find faults).	22
11	**Education and data:** Help customers to understand and manage their electricity consumption and costs through education and data.	19
12	**Offer small and medium businesses a range of different services:** Offer small and medium businesses a range of different services and prices so they can choose what they want in terms of reliability, account management and customer service.	16
13	**Premium services:** Provide services to those who are willing to pay for them, instead of all customers contributing.	8
14	**Increase digital security:** Increase digital security to protect customers' personal data related to their energy usage.	8
15	**Tailored approaches to account management:** Provide small and medium businesses more tailored approaches to account management and different levels of support depending on their needs and size.	5

5.1.2 Customer Independence and Flexibility

Solar

When asked for an in-principal selection of options for how they would like solar to be able to access the grid, most participants favour customers having maximum flexibility for importing and exporting solar to the grid.

Two-thirds of Customer Panel members said they would prefer that anyone who wants to install solar should be able to connect to the network and export their excess energy to the grid at any time. This option was particularly favoured by those under financial pressure.

The main reason given for choosing this option is interest in maximising customer flexibility rather than reducing pressure on the network.

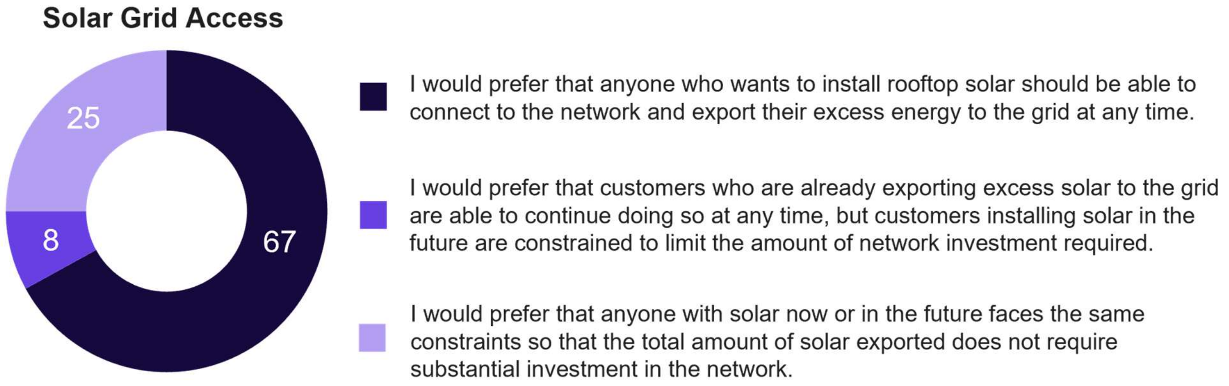

Figure 17 – In principle customer preferences for solar access

Enabling broad access to exporting energy into the network for existing and future solar customers (exporting at any time) requires a range of approaches and investments to optimise hosting capacity. It also requires new customer offers such as dynamic or flexible connections to more dynamically allocate hosting capacity to customers rather than imposing static limits.

Electric Vehicles

Similarly to solar, when asked for an in-principle selection of how they would like Electric Vehicles to be able to access the grid, there were diverse views.

Most participants felt that charging should be allowed at any time convenient for the electric vehicle owner as maximising customer flexibility (such as overnight charging) would be important to support the take up of electric vehicles. This view was most strongly supported by innovators.

But, mindful of grid constraints and associated costs, just under half supported this level of flexibility for exporting excess energy back to grid.

One-in-five felt that both charging and exporting should be limited to the times when it would most benefit the grid and other customers.

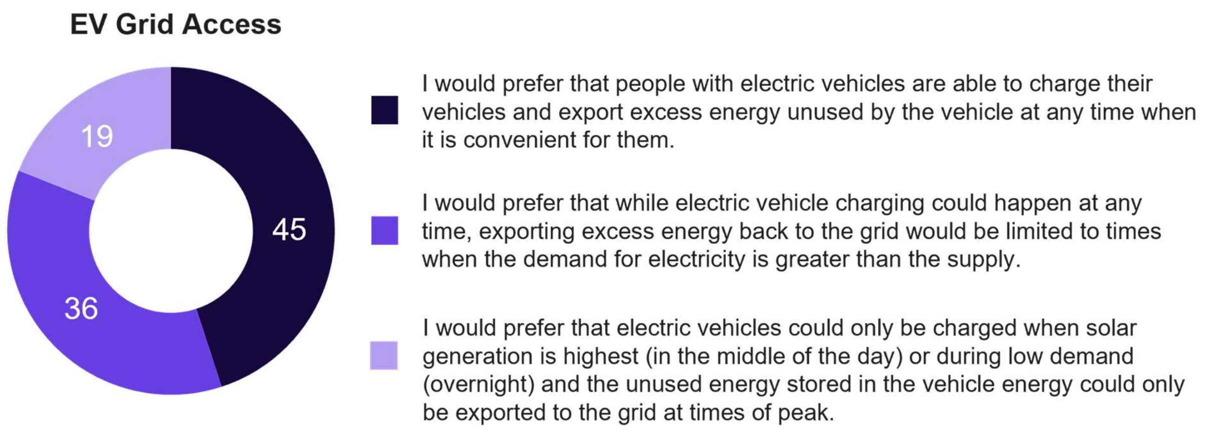

Figure 18 - In principle customer preferences for EV grid access

This feedback further reinforces the need to a dynamic connection offering and that such an offering will need to be bi-lateral – catering for input and export envelopes for both solar and EV load flexibility.

5.1.3 Future Tariffs

Customers were then asked their preferences regarding different types of existing tariffs. Customers told us that if they had the choice, 87% would choose a cost reflective tariff for their household or business as shown in Figure 19. This would enable customers to receive the financial incentive to change their behaviour.

Figure 19 – Customer Panel cost reflective tariff preferences

Customers then explored new tariff concepts such as solar soaking with an incentive to use energy during daylight hours and solar export charges for excessive solar exports during daylight hours. Customers were asked if they would support the introduction of these tariffs with both broadly supported at approximately 70% support across the participants. The results from each of these are shown in Figure 20 and Figure 21 below.

This feedback demonstrates that tariff-based and cost reflective signals are valued by customers. It also shows the need for tariff reform to be included in our DER integration plans.

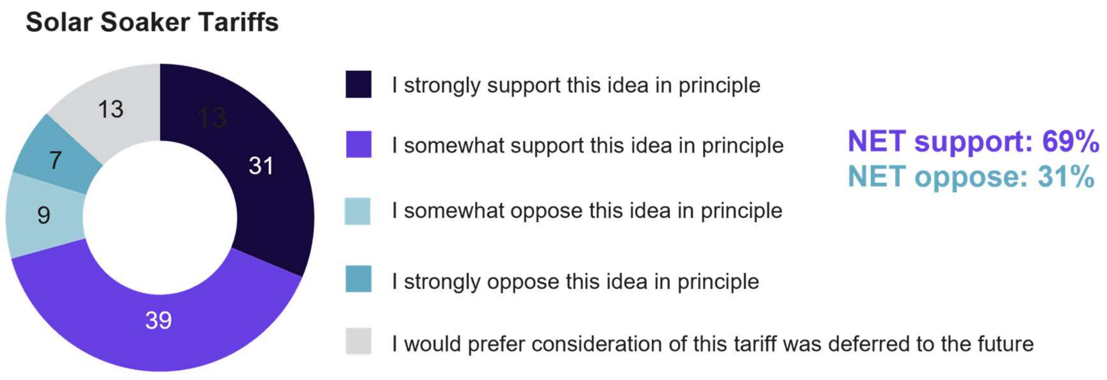

Figure 20 – Customer Panel solar soaking tariff preferences

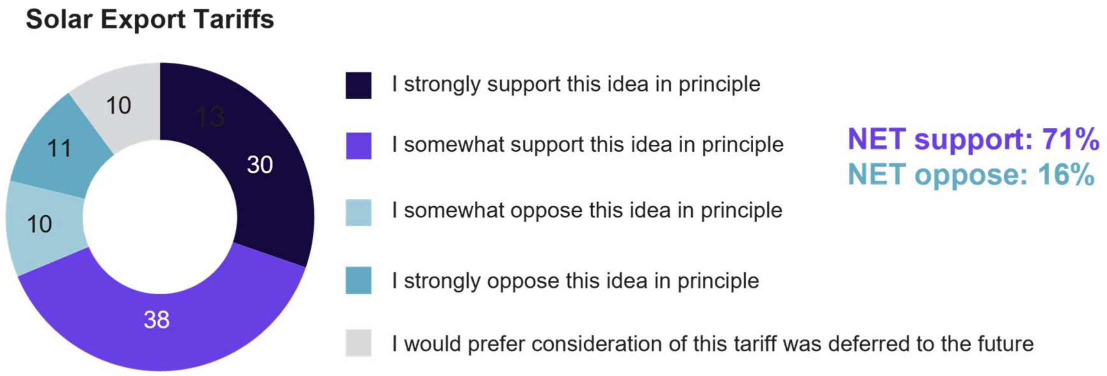

Figure 21 – Customer Panel solar export tariff preferences

5.2 Plan Overview

Our customer feedback revealed a common thread of flexibility and dynamic operations to be embedded in the network of the future. To be able to deliver on this level of service as a DSO we need to invest in the systems require to enable this. We have developed our plan on foundational actions that will enable us to offer future services aligned to our customer preferences and to avoid unnecessary augmentation to the network. We have also included our DSO operations plans to deliver the bi-lateral flexibility our customers are seeking for solar and EV's long term.

We have integrated our new cost reflective and solar soaking tariffs into our plan in line with customer feedback and consider this prior to network investment.

Our DER integration plan outlines 7 intervention actions that alleviate curtailment and enable the integration of higher levels of DER without significant impacts to our customers. Our plans prioritise customer and operational solutions prior to considering traditional augmentation. The Plan is outlined below in Figure 22 and the actions are grouped into 4 key focus areas:

1. **Enabling Systems**
2. **Tariff Reform and Demand Flexibility**
3. **Network Capability and Operational Optimisation**
4. **DSO Operations**

The hierarchy of intervention actions is intentional, and each action builds upon the previous. That is, we will only invest in each action after considering the remaining constraints any upstream intervention cannot alleviate.

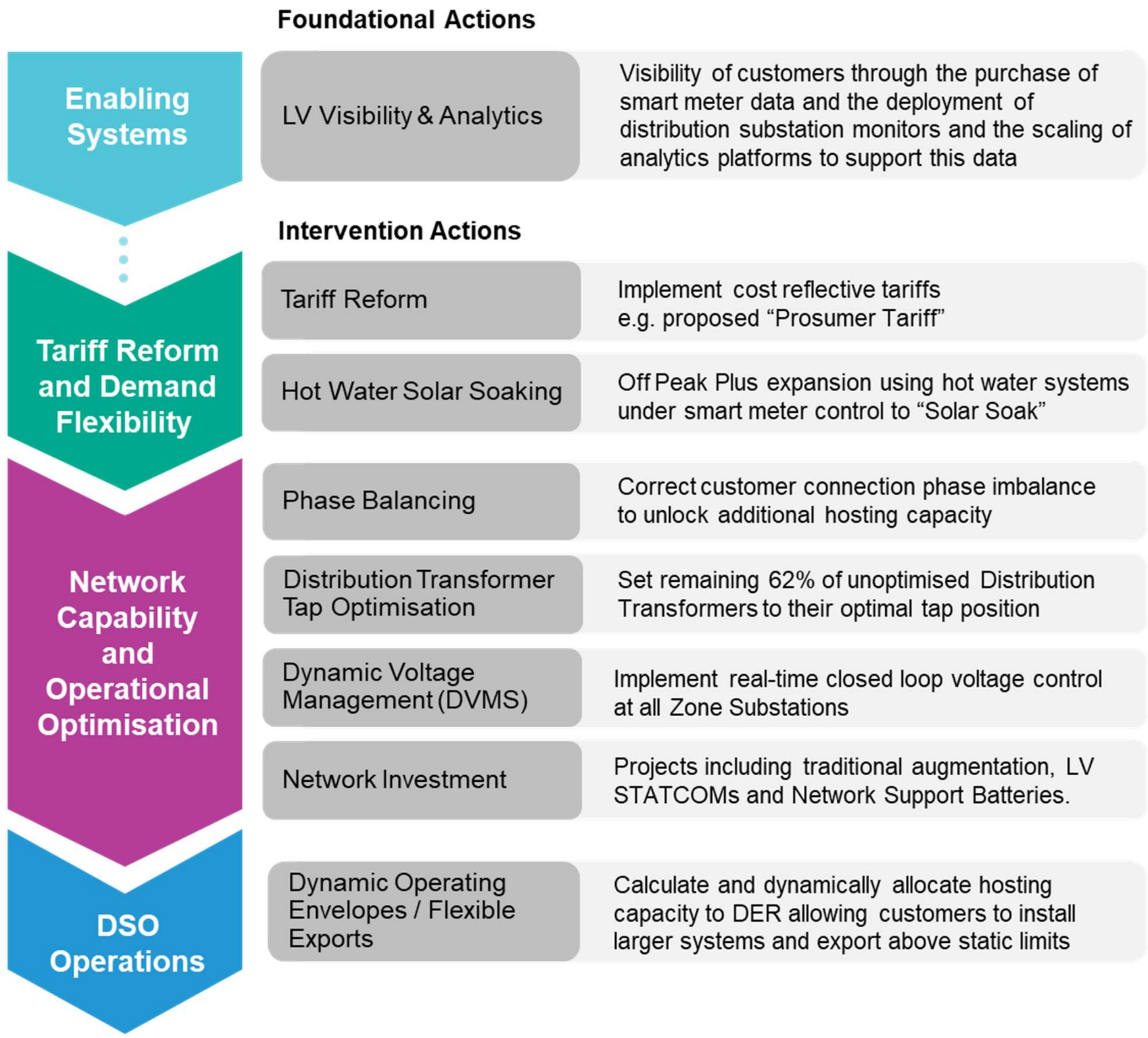

Figure 22 – DER Integration plan

The remaining sections of chapter 5 describe each intervention action in greater detail.

5.3 Enabling Systems

5.3.1 LV Visibility and Analytics

LV visibility and analytics (LVVA) is critical to efficiently supporting two-way energy flows from DER and for networks to deliver their DSO functions in line with regulatory reform. It enables improved hosting capacity through operational actions and dynamic LV voltage management, improving the utilisation of existing network assets. LVVA underpins all the intervention actions included in our proposed DER Integration Plan.

LVVA also contributes to improved customer safety, reliability and operational efficiency as demonstrated by our LV visibility and analytics platforms trials described in section 3.3.4 as well as shown through other jurisdictional and international experience. These benefits will not drive our visibility access strategy for DER Integration; however, their incremental value is significant and quantifiable.

Potential Visibility Sources

There are multiple potential sources of LV visibility. Each data source comes with varying characteristics and benefits as summarised in Table 9 below.

Table 9 – Visibility sources

Visibility Source	Distribution Transformer Monitors	Smart Meters (Power Quality Data)	Network Devices (Meter Board)	DER Inverter
Key Characteristics & Considerations	• High accuracy and granularity (1min - 5min data streams). • Comprehensive dataset for the LV network (per phase voltage, powers & harmonics) • Real time data delivery managed by network • Complete power flow coverage of distribution transformer (all customers) • Voltage visibility only applies to start of the LV feeder (first portion)	• High accuracy and granularity (5min data streams). • Comprehensive dataset (per phase voltage, powers) • Delayed and real time data delivery options (higher cost) • Provides voltage visibility across LV feeder including end of line • Provides phase unbalance estimation at end of line	• IoT devices have lower accuracy than smart meters (cost trade off) • High granularity (1min - 5min data streams) in real time. • Ongoing data costs (opex) equivalent or greater than purchasing smart meter data (high recurrent costs) • Duplication of market metering issues - meter board installation complexity • Uncertain asset lifetimes and ongoing replacement costs	• Lower / inconsistent measurement accuracy – useful for indication only • Limited and inconsistent dataset (may improve with CSIP aus / IEEE2030.5 compliance over time) • Partial measurement of customer installation and often remote connection point (sub-mains) • Measurement at DER asset not connection point. • Limited availability - customer Wifi connection (typically)
Summary	Comprehensive and mature visibility source supplementary to customer level data	Mature, robust, highly accurate and well-defined data source	Provides no additional technical benefit to smart meters and likely incurs higher overall costs and complexity	Emerging visibility source which remains to be proven at scale and requires maturity in standardisation.

Given the above considerations, our focus for visibility sources for FY25-29 will be via smart meter PQ data access and Distribution Transformer Monitoring which are both mature, proven, and consistent sources of visibility. Furthermore, the AEMC's power of choice review is supportive of improving network access to power quality data from smart meters by developing a standardised basic power quality service and delivery mechanism to improve the overall cost profile of the provision of this data.

Visibility Requirements for RCP FY25-29

We have adopted the following principles in determining our required level of LV visibility:

- Balancing cost outcomes for customers (noting the bill impact of recurrent opex costs)
- Growing our visibility commensurate to our analytics maturity. That is, not expanding visibility ahead of our expected capability to analyse the data and implement the use cases.
- Establishing a minimum viable visibility level to enable all our DER Plan interventions (refer to Table 10)

Table 10 - Visibility required to support DER intervention actions

Intervention Action	Required Data Source	Minimum Visibility Required	Equivalent Penetration	Comments
Transformer Tapping	Voltage at customer level (smart meter data)	3–4-meter points per LV circuit (most customers are single phase)	20-25% (4/15)	Our tap setting records are untrustworthy or often missing. To confirm the present tap setting currently requires an in-field inspection and temporary monitoring if considering tap adjustment. Tap optimisation requires knowledge of the LV circuits peak and minimum load end of line voltage and comparison of this to AS61000.3.100 V1 and V99 limits. A sample of smart meter measurement points (3-4 accounting for predominance of single-phase customers) towards end of each LV circuit is required (on average each LV circuit has 15 customers)
Phase Balancing	Voltage at customer level (smart meter data) + Distribution Transformer Monitor	Sample of smart meters plus DTX Monitor	As above + distribution transformer monitor	End of LV circuit sample provides estimation of voltage unbalance factor (VUF). Distribution transformer monitors provide complete per phase power flows to assist in customer load and DER balancing across phases. Note that high unbalance networks typically correspond to high utilisation networks and therefore the deployment of distribution transformer monitors to assist with correcting unbalance has a strong correlation with the targeted deployment for accurate DOEs.
DVMS	Voltage at customer level (smart meter data)	Min 20% across each Zone Substation that has DVMS applied.	20%	Victorian networks (such as United Energy) have experience with operating DVMS. The DVMS only operates once a minimum 20% of customer measurement points has been returned from the AMI fleet. This is to ensure the DVMS has enough statistical visibility to ensure that customers are not driven outside of AS61000.3.100 V1 and V99 bounds. Broad coverage is also required to detect misaligned distribution transformer tap settings which would restrict the DVMS from operating effectively.

Intervention Action	Required Data Source	Minimum Visibility Required	Equivalent Penetration	Comments
Generalised DOEs	Broad based voltage at customer level (across LV networks)	Ideal coverage 50%-75%	Min 25% Ideal 50-75%	State estimation plays an important role in achieving generalised DOEs. The ARENA 'Solar Enablement Initiative' [3] (see Figure 23) determined that 25% coverage is required at a minimum to run state estimation with a quantifiable uncertainty, with 50-75% coverage required to produce accurate estimations.
Accurate Targeted DOEs	Coverage of high penetration Distribution Transformers	Transformer Monitor at every Dist TX where highly accurate DOE's are required	Dependant on DTX utilisation (reverse and forward flows)	For accurate DOE's at a minimum a Distribution transformer monitor is required in addition to sample of customer nodes (ARENA 'Solar Enablement Initiative' and ARENA 'Project Shield').

Across all these DER targeted use cases for LV Visibility, a common minimum access requirement is 20-25% broad based visibility with increased visibility beyond this targeted to specific areas of the network with high DER utilisation. Without this base visibility many of these use cases could not be achieved or only achieved through very costly, non-scalable and time-consuming means (such as truck rolls for temporary monitoring).

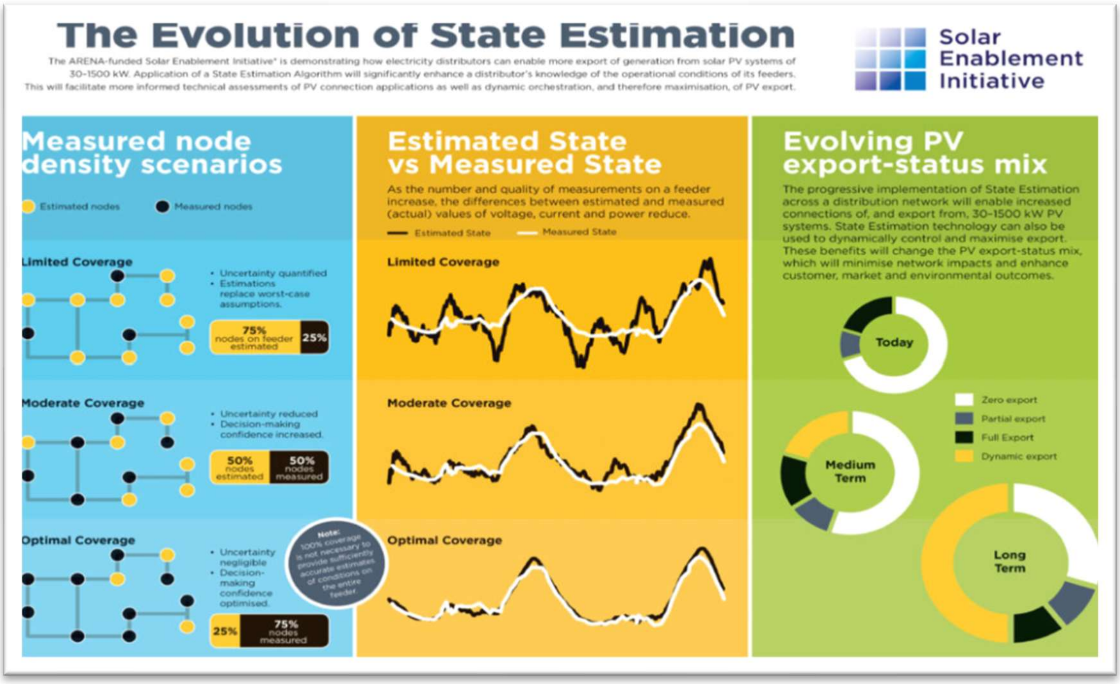

Figure 23 – Summary graphic sourced from ARENA project 'Solar Enablement Initiative' [3]

Analytics Platforms

The implementation of analytics is critical to deriving the maximum value out of visibility sources as demonstrated by our LV analytics trials. It is also critical to merge all available visibility sources into a common platform, including smart meter power quality data, smart meter interval billing data as well as transformer monitoring data and provide automated algorithms that inform the operational strategies and outcomes listed in Table 10.

We will expand our existing low voltage analytics trials into business-as-usual support tools for DER management and broader business efficiency. For this we will leverage market leading off-the-shelf analytics platforms which have emerged due to commonality in use cases across networks rather than develop in-house / bespoke analytics which is expected to be significantly more costly.

5.4 Tariff Reform and Demand Flexibility

5.4.1 Tariff Reform

As an initial step to increase DER hosting capacity on the network we plan to introduce new tariffs which help manage the constraints we are forecasting. Tariffs offer a widespread non-network opportunity to deliver greater value to customers whilst better managing the energy consumption patterns on the network without significant investments.

In the design of tariffs, we assume electricity is strongly price inelastic. Our forecasting model predicts a 10% increase in price will result in a 1% reduction in the baseline customer demand.

It should be noted that in our recent customer forums there appeared a strong interest and willingness from customers on how they could contribute to a more efficient energy ecosystem by altering the way they used their power. This appears to be a strong opportunity, that requires buy-in and support from the retailers.

Prosumer (Solar Soak) Tariff Trial

In FY23 we are undertaking a Prosumer Tariff trial which has the following features:

- two-way tariff and solar soak period
- provides an incentive to shift excess export to times of peak network demand
- An export charge during the day with 'feed-in' reward at afternoon peak times
- Encourage use of behind-the-meter storage to support grid security and utilisation

A comparison of the prosumer tariff pricing structure against our standard demand tariff is provided below in Figure 24.

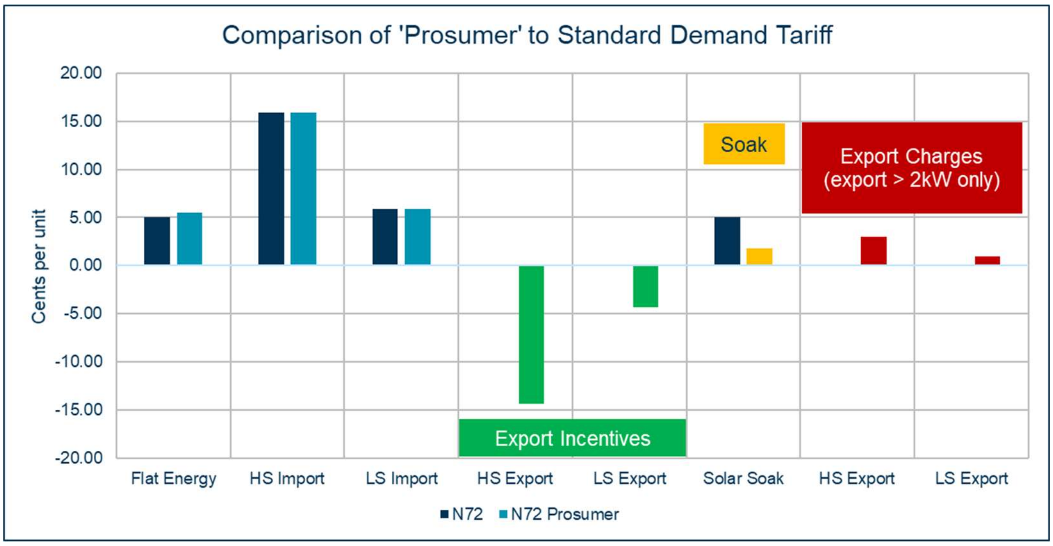

Figure 24 – Prosumer tariff structure vs demand tariff

Note: High Season (HS) is defined as the five months November through March. All other months are defined as Low Season (LS).

The progressive rollout of the prosumer tariff and the modified customer behaviour associated has been modelled out to 2040 through adjustments made to the baseline customer load profiles used as inputs to the DER scenario builder. The price signalling results in a reduced night-time peak with energy moved into the off peak and solar soaking period as illustrated on the average day profile for 2040 in Figure 25.

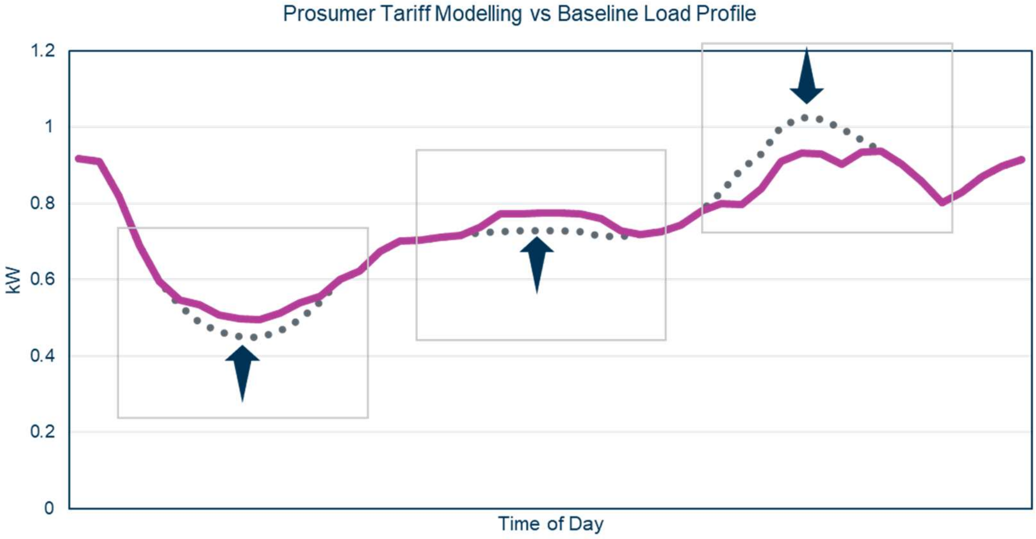

Figure 25 – Adjusted average day load profiles due to adoption of prosumer tariff modelling

5.4.2 Hot Water Solar Soaking

Our Off Peak Plus pilot project (described in section 3.3.7) demonstrated that smart meters can successfully be used to deliver flexible and reliable hot water solar soaking without impacting customer amenity.

Off peak hot water control is transitioned away from ripple control to the smart meter by default wherever there is a metering exchange under the power of choice framework. This is done as a static time schedule through the smart meter. However, the Off Peak Plus project demonstrated that there is additional value to be gained for the network and market by utilising a dynamic control approach through a remote API interface implemented by the metering provider.

We plan to target further rollouts of Off Peak Plus as an intervention action to improve hosting capacity, by shifting hot water heating loads into the solar period.

An example of the changed average daily load profile of an Off Peak Plus customer with solar soaking is shown below in Figure 26 and illustrates the benefits this intervention can bring in alleviating constraints that rooftop PV introduce into the network.

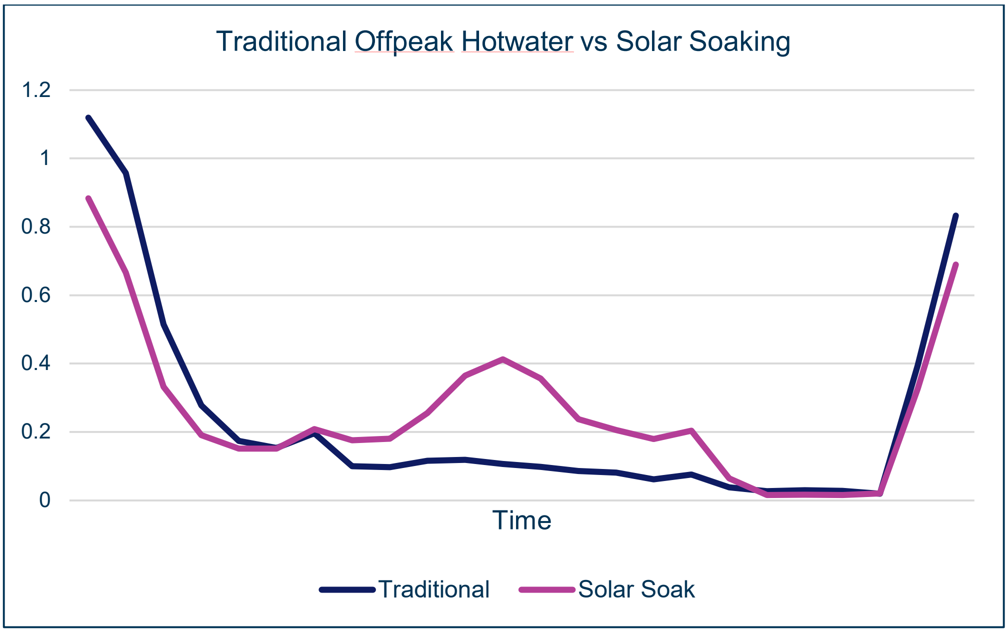

Figure 26 – Average day example of off peak plus solar soaking vs traditional off peak hot water

In addition to the benefits that solar soaking can provide this investment is also an alternate to:

- replacing like for like end-of-life off peak ripple control systems in existing substations
- installing new ripple control systems in a new substation that partially supplies an existing brownfield area where not all customers have transitioned to smart meters yet.

5.5 Network Capability and Operation Optimisation

5.5.1 Phase Balancing

Ideally, the connection of all customers should be spread evenly across all phase conductors to balance the loading on the network. However, unbalance exists typically weighted towards the conductor closest to the property being connected.

Through LV visibility, analytics platforms can identify the level and location of unbalance on the network allowing for corrections to be made at the point of connection by moving loads to a different phase.

Using the LV analytics platforms trialled in section 3.3.4 we have determined that the average unbalance on LV networks is approximately a 50%/30%/20% split across the available three phases. This is measured by the observed voltage on each of the phases through the purchased smart meter data.

An example of the Gridsight platform used in this analysis is shown below in Figure 27.

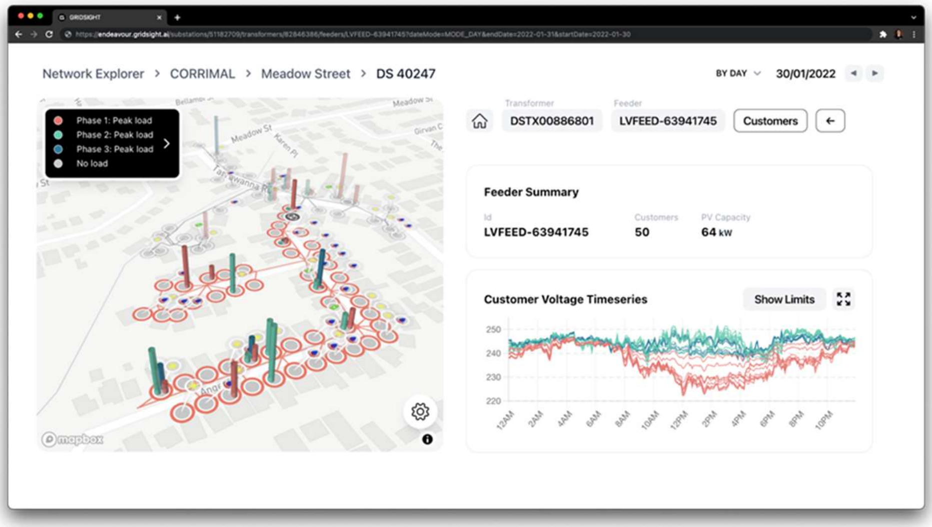

Figure 27 – LV Analytics tools used for identifying phase unbalance from a sample of smart meter data (in this case high daytime DER related unbalance)

Correcting this imbalance through operational actions in a targeted manner like the tap optimisation rollout is what we plan to deliver in our DER integration plan.

5.5.2 Distribution Transformer Tap Optimisation

As discussed in section 3.3.8, Endeavour Energy has had a successful tap optimisation program to date. Our plan is to continue this program and to further reduce the constraints on the network reducing hosting capacity moving forward.

5.5.3 Dynamic Voltage Management System (DVMS)

Voltage management on distribution networks is becoming increasingly complex with two-way power flows across the distribution network due to DER. Moreover, these power flows can rapidly change based on prevailing weather conditions. As such it is no longer feasible to have a static “set and forget” approach to voltage management.

With the increasing availability of smart meter data, many networks are exploring advanced approaches to voltage management such as implementing Dynamic Voltage Management Systems which integrate near real time smart meter data in a closed loop scheme that dynamically adjusts target voltage settings at the zone substation level. This is shown conceptually below in Figure 28.

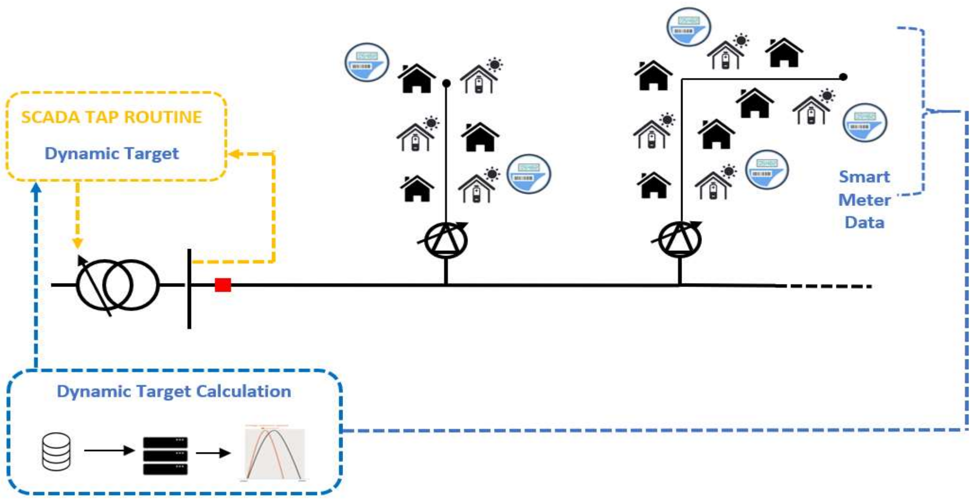

Figure 28 – DVMS concept

As discussed in section 3.3.3, Endeavour Energy's modern substation RTUs have the capability to receive dynamic target voltage settings via SCADA which now enables the application of a DVMS without significant capital investment. The main associated costs with operating a DVMS is smart meter data access charges and associated analytics platform costs.

5.5.4 Network Investment

We plan to maintain a network capital investment program that is aimed at DER Integration, that is hosting capacity improvement in certain locations of the network which are VaDER justified.

Options will include traditional network investments as well as new technology options leveraging network technology pilots and trials undertaken and proven in RCP19-24. This will include:

- Distribution Transformer Tank Replacement
- LV STATCOMs
- LV network amplification and splitting
- Network Batteries

We will assess these investments according to a cost benefit hierarchy as well as considering the correct technical solution for each location

5.6 DSO Operations

5.6.1 Dynamic Operating Envelopes / Flexible Exports

The ESB's DER Implementation Plan (previous shown in Figure 2) has identified Dynamic Operating Envelopes as priority action. Also related to this is the embedding of Emergency Backstops for minimum system load. It is commonly accepted that the DOE can serve both purposes, that is: optimising exports as well as communicating emergency backstop conditions.

Furthermore, the AER's DER Integration Guidance note states that networks should provide "details of the DNSP's plan (if any) for the implementation of dynamic operating envelopes (DOEs), which may include the timing of trials, methods for capacity allocation and consumer engagement".

Our Considerations for Implementing DOEs

Our average residential solar system size trend shows a clear linear growth trajectory towards larger systems. This has already exceeded on average our standard 5kW static limit. Our customers intend to continue to install larger solar systems and therefore our static limits will (and already are) becoming a constraint to this. Given the compliance to static limits is poor (as discussed in 3.2.4) there is additional impetus to implement Dynamic Operating Envelopes which would improve compliance and equity of export access (reduce the number of customer's taking more than their "fair share").

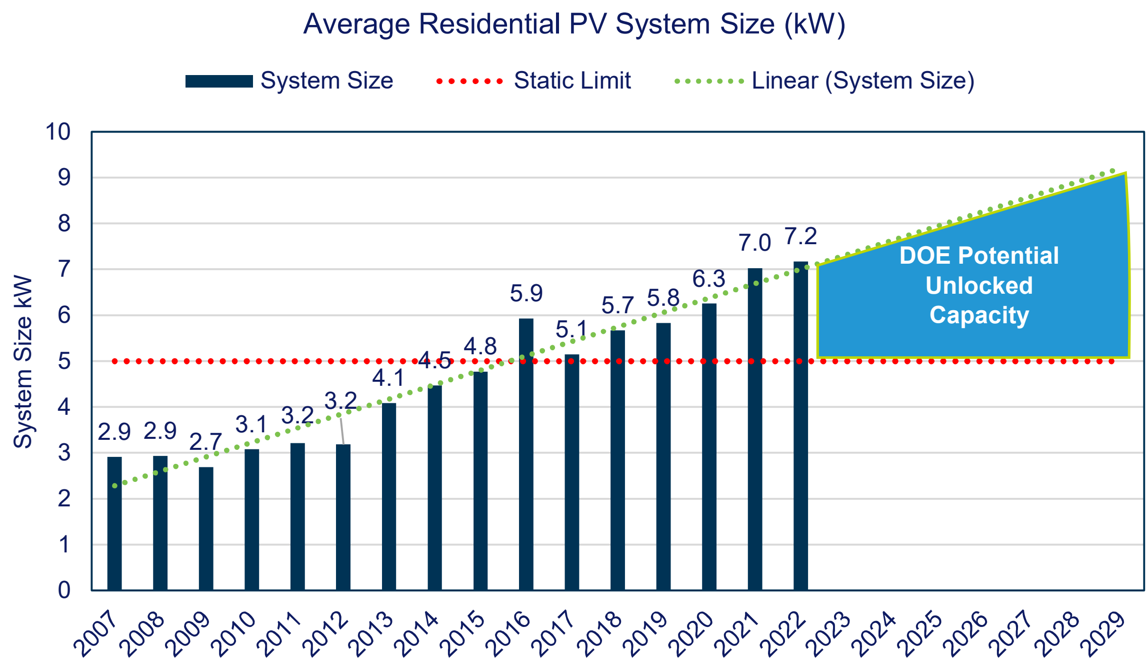

Figure 29 – Measuring DOE unlocked capacity

Minimum / emergency backstop capability is most effectively delivered via the DOE mechanism rather than through other means (for example through a smart meter hard wired disconnect) or crude voltage increase schemes. However, for backstop to be meaningful and effective to support system security a significant portion of the solar fleet needs to be able to be responsive to minimum demand events as directed by AEMO. This dictates that the implementation of backstop capability on any new solar system should be implemented well ahead of forecast system security concerns (for Endeavour Energy in NSW).

Implementation Plan for DOEs

We are currently developing a detailed DOE implementation plan and trial project with the aim to have a flexible exports offer by FY25. At a high level our proposed timeline for DOEs is as follows in Figure 30.

Figure 30 – DOE Implementation Plan

DOE Pilot (FY23 and FY24)

We plan to trial DOEs at existing and new customer sites in a controlled manner. This will help develop our technical understanding and experience with DOEs as well as identify and test end processes and systems required to achieve DOEs. It will also be an opportunity to engage with customers and stakeholders on DOEs and the benefits they provide.

Our pilot will leverage off the experiences and learnings from other networks which have trialled or are trialling DOEs to leverage their experience and apply their learnings.

Flexible Exports Offer (FY25 onwards)

We intend to develop and have available flexible (dynamic) exports offer for customers by FY25.

As such we plan to implement a DER Management System (DERMS), customer connection portals and associated installer processes that:

- Enrols a new DER customer to a Dynamic Exports connections offer
- Uses LVVA to calculate DOEs informed by local distribution network level constraints. This includes utilising the DOE mechanism for passing through AEMOs minimum demand curtailment directives (as applicable)
- Communicates these constraints to applicable DER via standardised protocols such as IEEE2030.5 / CSIP AUS

How we intend to allocate DOEs

The allocation of DOE's is the subject of trials (such as Project Edge and SAPN's Flexible Exports trial) as well as academic research. There are two boundary options for the allocation of DOEs to customers:

- Equal/Equitable Dispatch: allow all customers the same incremental kW export opportunity
- Optimal/Maximum Dispatch: allow the maximum total kW export.

The appropriateness of these approaches or hybrids thereof requires further trials, research, and customer consultation. It is also important to note that both or many variants may be required depending on system conditions. For example, in the event of lack of system generation then the optimal/maximum dispatch approach arguably leads to the best overall community outcome by contributing to avoiding load shedding.

6. DER Integration Business Case

6.1 Our Approach to VaDER

6.1.1 VaDER components

The AER has provided guidance on how networks should value investments that alleviate DER curtailment. An overview of the VaDER components that have and have not been included in this modelling is shown below in Figure 31.

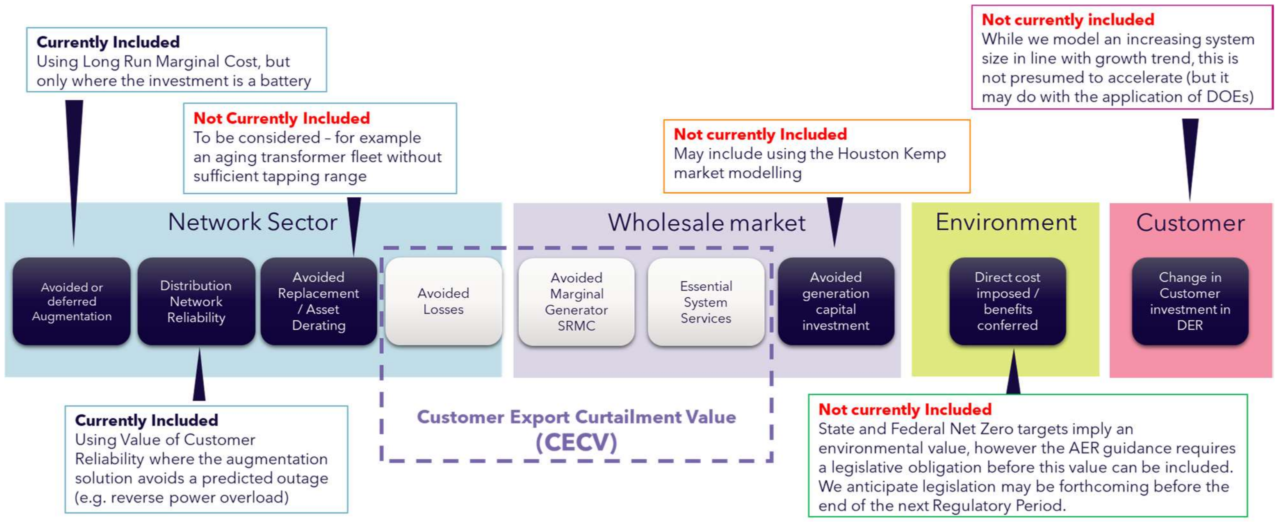

Figure 31 – VaDER components breakdown

6.1.2 Stakeholder Feedback on CECV

We consulted on our approach to VaDER and specifically the Customer Export Curtailment Value (CECV) as part of our deep dive sessions with customer and stakeholders. This engagement process is described in Section 2.2. We provided information on the CECV estimates from the AER (Oakley Greenwood) as well as Houston Kemp and highlighted the variation in these estimates. Given this variability we sought stakeholders' views on adopting a position of averaging these two credible CECV estimates.

We received clear feedback, particularly from the regulatory reference group, that we should only apply the AER's CECV estimates, but should further explore the case for valuing environmental benefits (discussed further in section 6.1.4).

6.1.3 Our Assumed CECV

In line with stakeholder feedback, we have adopted the AER's CECV forecast (Oakley Greenwood). An illustration of the average daytime CECV value per year is shown Figure 32. We have incorporated and utilised the full 30-min timeseries CECV data in hosting capacity simulation tool applied to the alleviation profile for every simulated times-step.

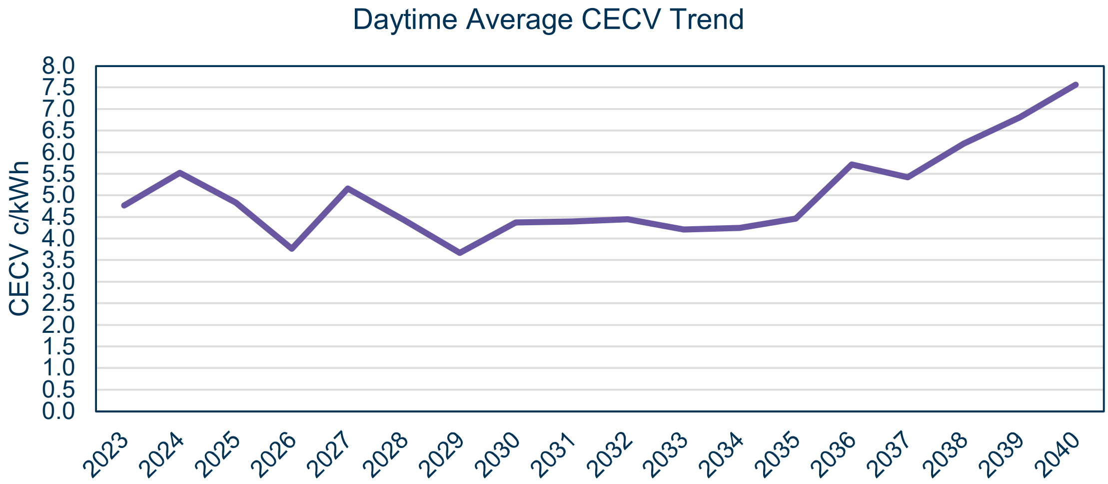

Figure 32 – Oakley Greenwood Average Daytime CECV Trend

6.1.4 Environmental and Avoided Generation Investment Benefit

We are engaging KPMG to review our approach to VaDER more broadly, specifically the materiality and validity of including Environmental and Avoided Generation Investment Benefits utilising our overall network wide alleviation profile from our hosting capacity modelling.

A shorthand method was used to get an indication of the materiality of avoided generation investment and environmental benefits. Preliminary analysis from this work has shown that [4]:

- Environmental benefits is likely significant representing an average 33% increase above the CECV on average based on a sample year of 2025. This analysis was conducted using emissions factors for each marginal generator from the AEMO ISP as well as an assumed carbon price of $30/tC02.
- Avoided Generation Investment benefit is less significant at 4%.

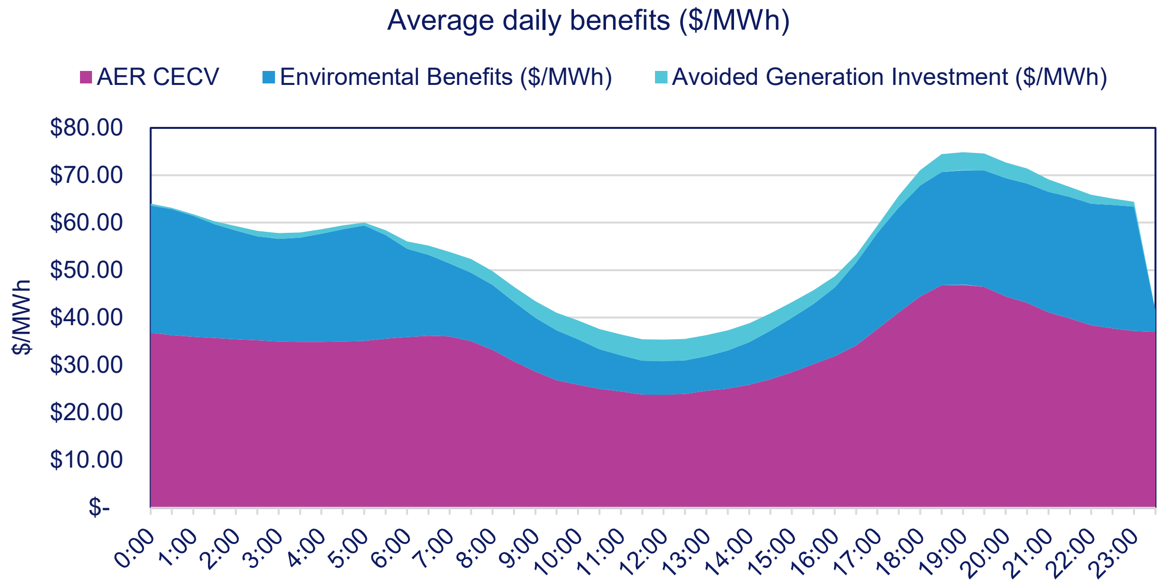

Figure 33 – KPMG short-hand modelling of environmental and avoided generation investment benefits (2025) [4]

We have not included either of these benefits in this DER Integration Business Case VaDER framework, however we intend to further investigate its materiality and validity for inclusion in the final submission.

6.1.5 Other Non-VADER Benefits

We have included other non-VaDER benefits for completeness where these are relevant and tangible such as within our LV Visibility cost-benefit analysis. However, these non-VADER benefits are incremental and do not inform the scale or strategy of any of our proposed DER Integration related investments.

6.2 Our Business Case Modelling Approach

6.2.1 Overview

To support our DER Integration Business Case, we have developed a process to simulate and value DER at a granular level. This process is shown below in Figure 34.

The Hosting Capacity Simulation Tool described in section 4.2 combined with the AER CECV forecast described in section 6.1.3 provides a quantified alleviation result for every intervention action simulated in the load flow engine. These results combined with VaDER benefits, other benefits such as Safety and VCR, and costs associated with implementation of the intervention actions are all fed into the NPV model. The result of this work is presented throughout the remainder of chapter 6.

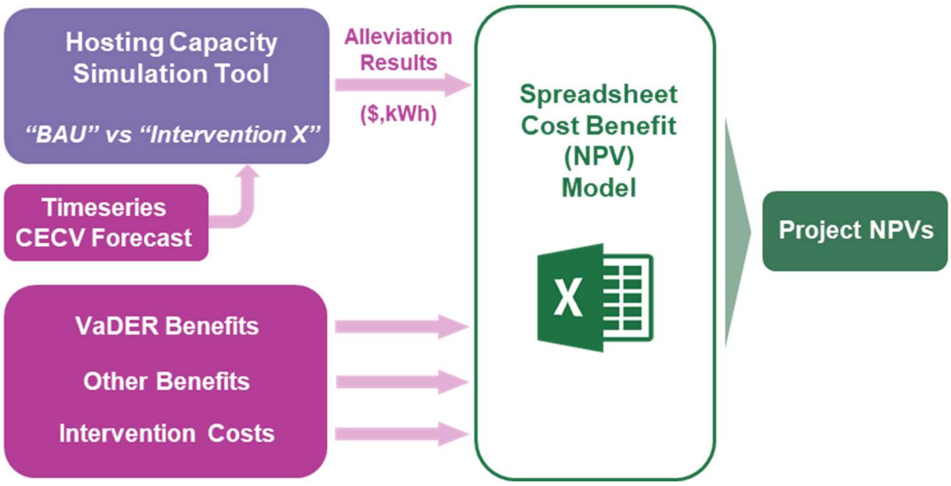

Figure 34 – Business Case Model

6.2.2 DER Forecast Selection

As explained in section 4.1, The AEMO ISP "Step Change" was selected as the central case and the focus of the modelling. Hydrogen Superpower and Progressive Change were selected as the High and Low cases respectively for the purpose of sensitivity analysis.

The simulation model was tested for each of the 3 forecast scenarios with the percentage variation from the central case (Step Change) shown below in Figure 35 by the dashed lines. A weighted average approach using the Delphi Panel 2 likelihood results was then constructed using the following weightings:

- Progressive Change – 29%
- Step Change – 50%
- Hydrogen Superpower – 17%

The outcome of this study resulted in Step Change being selected as the forecast that will be used in the business case modelling detailed in the remainder of this document. Step Change is considered an appropriate representation of the weighted average given the small level of deviations, and significantly reduces the resource intensive modelling requirements of the simulator by a third.

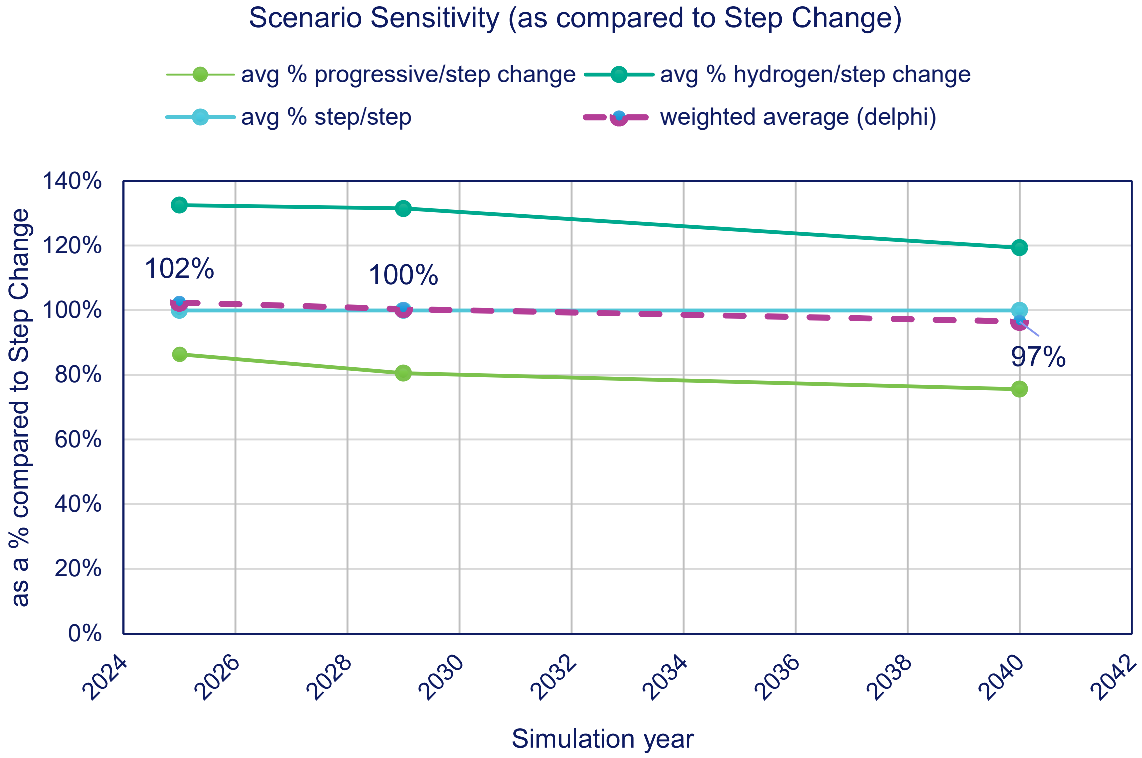

Figure 35 – ISP scenario modelled sensitivity

6.2.3 Defining the Base Case ("BAU") Scenario

A base case scenario was developed in the model to serve as a comparison case for all intervention actions listed in the DER Integration plan to be quantified against.

The base case was developed using the following key assumptions:

- Customers install PV and battery systems in accordance with the Step Change ISP forecast (as explained previously) translated to Endeavour Energy's network
- All new PV systems match the current average inverter size
- 100% of new inverters are compliant to AS4777.2020 Power Quality Response Modes (Volt-Watt and Volt VAR).
- No intervention actions are included. I.e., transformers are left on their current tap position and phases remain unbalanced.

Using the base case scenario, the forecasted network curtailment value was then determined for each year of the forecast as shown below in Figure 36.

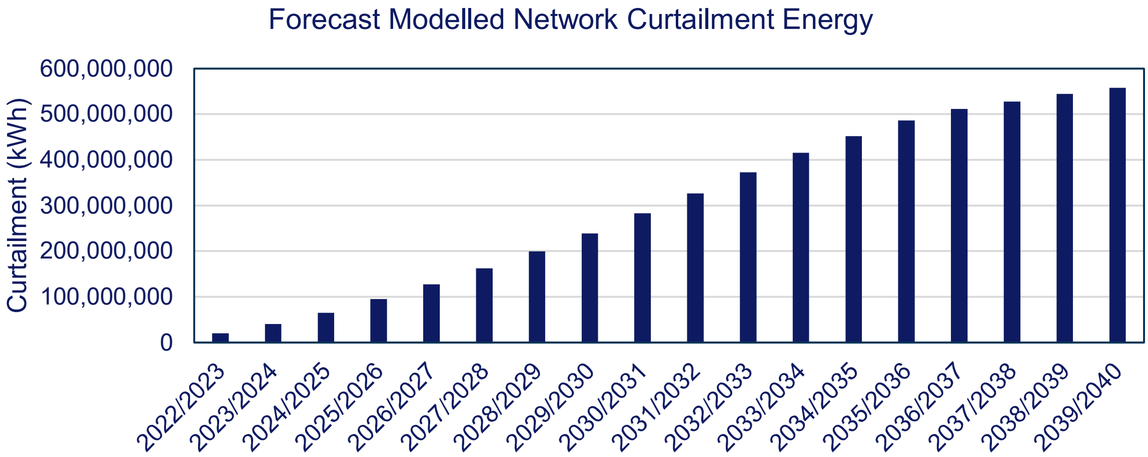

Figure 36 – Business as usual forecast curtailment kWh trend

Applying the CECV value to the Curtailment forecast results in the figures shown in Figure 37 for the BAU case.

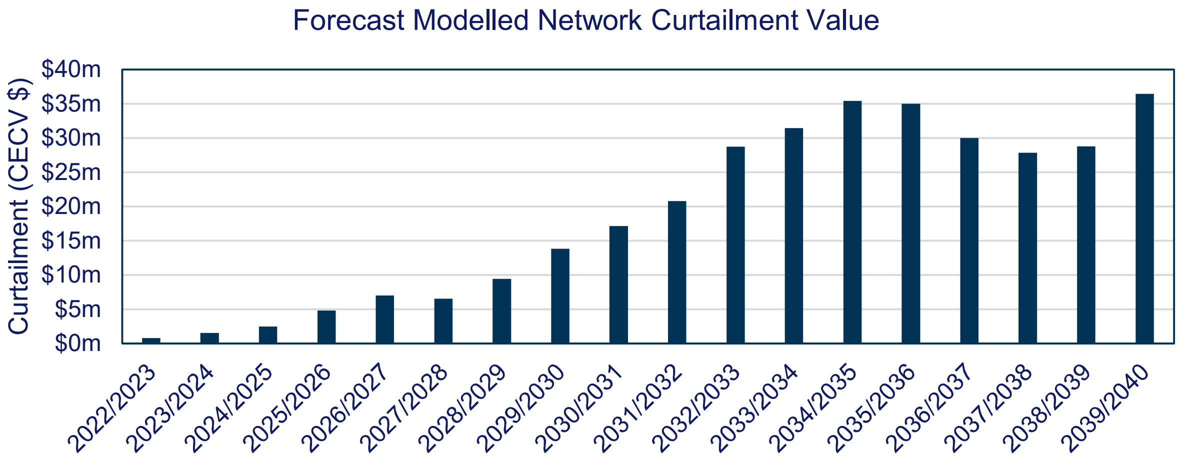

Figure 37 – Business as usual forecast CECV $ Trend

It should be noted that although the Tariff reform interventions planned by Endeavour were not included in the BAU modelling, the Step Change ISP forecast has Electric vehicle and Battery tariff reforms embedded within that were not removed in our BAU case.

6.2.4 Modelled Scenarios and Intervention Options

The assessment of the DER Integration intervention action investment benefits has been quantified by defining various intervention scenarios compared to the business as usual or base case. These intervention options are conducted sequentially (generally least cost operational actions to highest cost investment actions) to avoid double counting of benefits.

Table 11 – Modelled scenarios

Modelled Scenarios	Description of Scenario (Note: Each scenario is incremental/sequential to previous scenario)	Modelling Approach	Expected Outcome
Business as Usual (Unbalanced)	ISP "step change" scenario with existing static export limits. Model is tuned to represent realistic/typical LV phase unbalance.	Hosting Capacity Simulation	Establish a credible baseline Curtailment forecast (with realistic LV unbalance)
Tariff Reform	Modify baseline load profiles to increase solar soaking based on assumed forecast tariff adoption	Hosting Capacity Simulation	Modify BAU Curtailment forecast.
Phase Balancing	Phase balanced LV networks.	Hosting Capacity Simulation	Contribution to LVVA benefits (phase balancing)
Distribution Transformer Tap Optimisation	Determine optimal tap setting per Dist Tx and the forecast year the tap change is required	Hosting Capacity Simulation	Maintain tap changing program and forecast tap change volumes by year
DVMS	Modelled DVMS operation to measure the reduced curtailment benefits	Hosting Capacity Simulation	Contribution to LVVA and Dist Tx Monitoring benefits (real time visibility)
Hot Water Solar Soaking	Apply a hot water solar soak load profile to simulate the curtailment improvement	Hosting Capacity Simulation	Justify case for Rolling out Off Peak Plus
Network Investment (Augmentation)	After the above Interventions have been factored in the remaining curtailment per distribution transformer is tested for an economic case for augmentation	Spreadsheet model using hosting capacity simulation results	Inform Forecast DER Network Capital Investment Program
Dynamic Operating Envelopes / Flexible Exports	Upside scenario. Allows incrementally larger systems to be hosted on the network	Spreadsheet model (to be simulated using hosting Capacity Simulation tool in future)	Justify Investment in DOE's for flexible exports and Emergency Backstop capability

The associated total remaining curtailment value (network wide) post each intervention is shown in Figure 38.

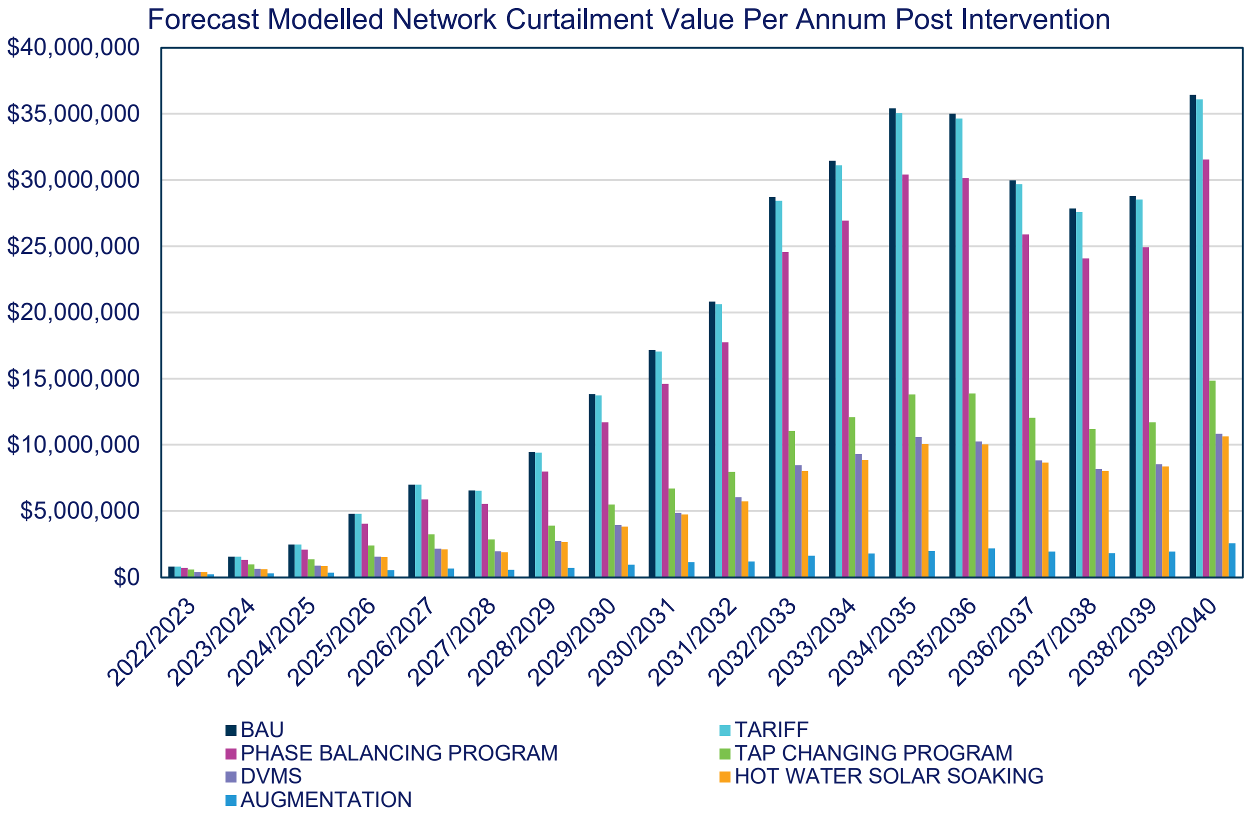

Figure 38 – Forecast CECV $ trend per modelled DER Integration plan intervention

It has been modelled that an investment of all the proposed interventions would reduce the average DER customer curtailment across the Endeavour Energy network from 9.3% total curtailment down to only 1.8% by 2040, as shown in Figure 39.

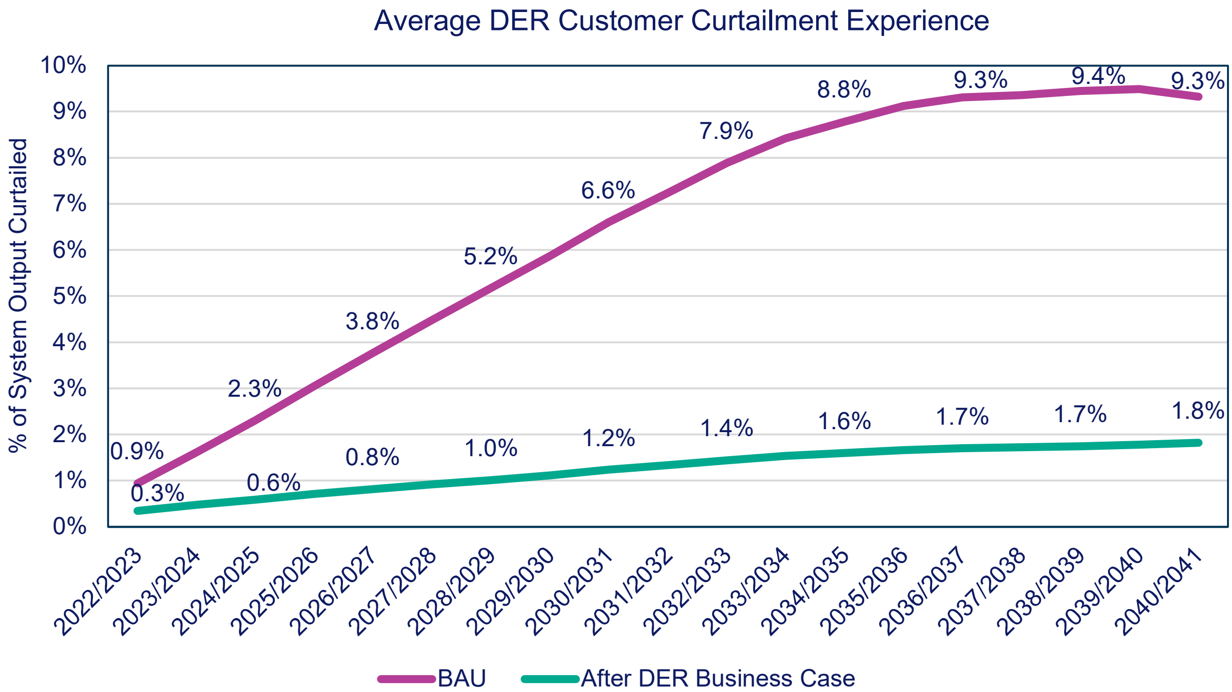

Figure 39 - Average DER Customer curtailment post all interventions

6.3 DER Integration Plan Modelling and Cost Benefit Analysis

6.3.1 LV Visibility and Analytics

Investment Strategy

LVVA is critical and foundational to enabling DER in distribution networks. LVVA is supportive of all the intervention investments in our DER Integration Plan.

In line with the LVVA strategy discussed in section 5.3.1, this business case targets a minimum viable level of visibility to enable DER Integration benefits. The visibility investment is made up of:

- A glide path from 15% (FY25) to 25% (FY29) access of smart meter power quality data as shown in Figure 40.
- A targeted Distribution Transformer Monitoring program for distribution transformers that exceed a modelled 50% reverse power flow penetration or >80% utilisation (forward loading) or combination thereof. This aligns to provision of accurate DOEs as highest likelihood of phase imbalance affecting voltage utilisation. This program forecast is shown in Figure 41 was derived through the hosting capacity modelling.

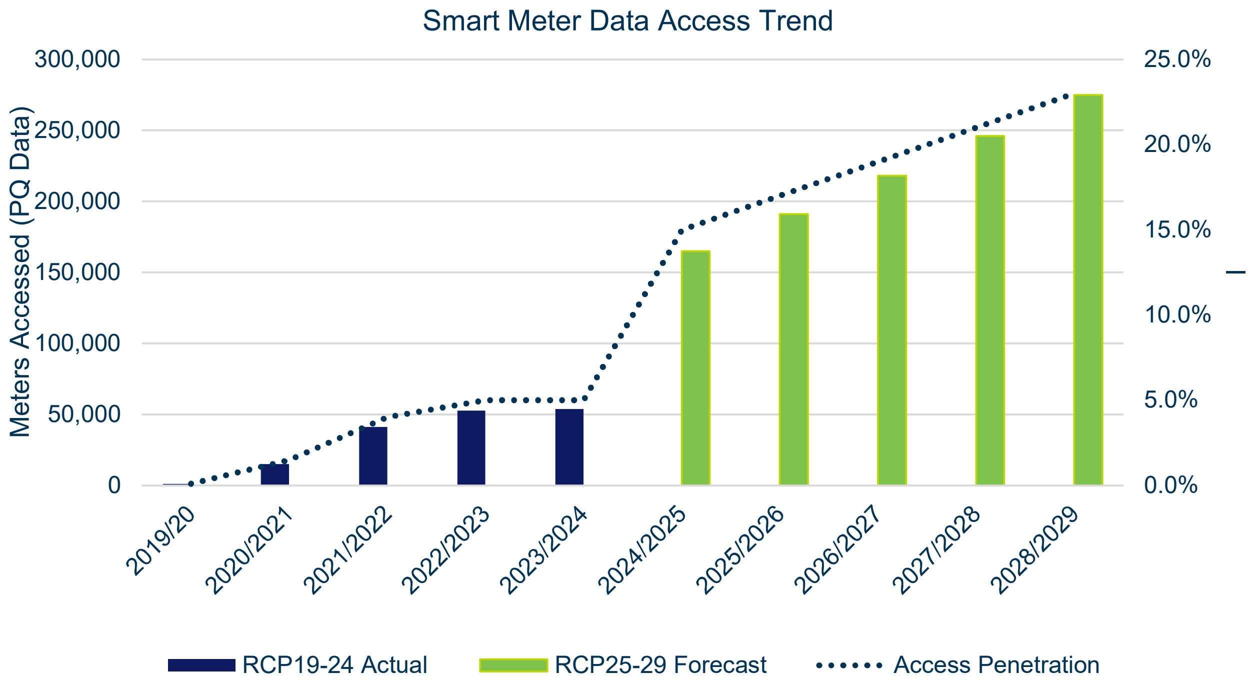

Figure 40 – Existing and projected smart meter power quality data access

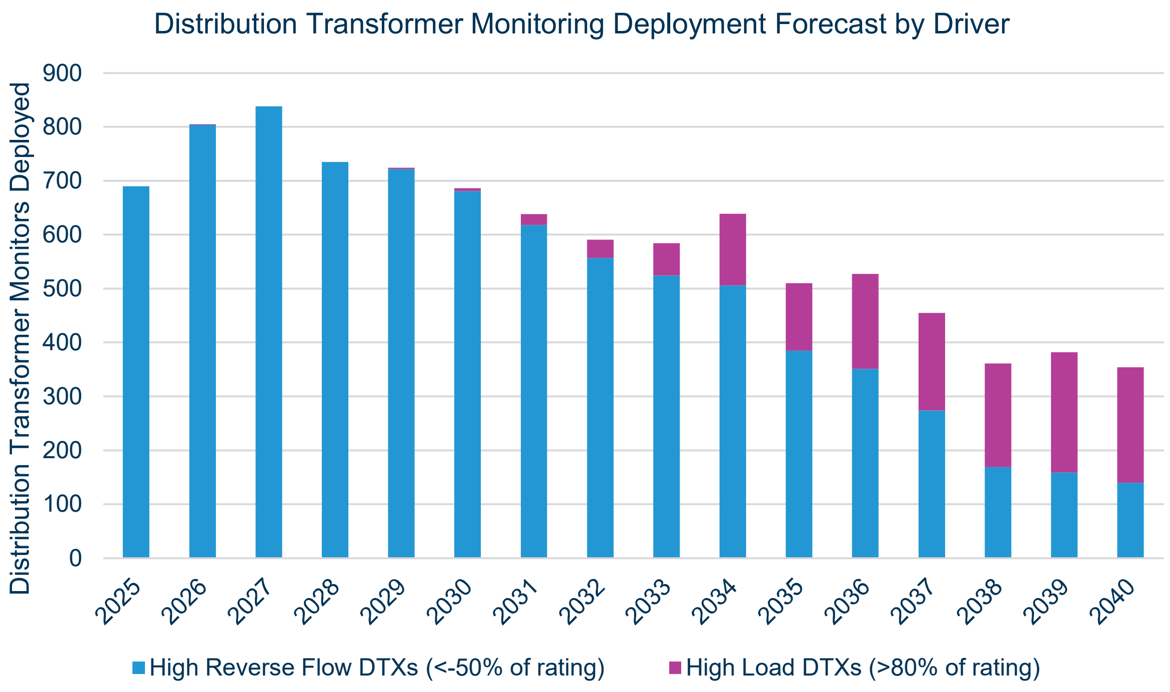

Figure 41 – Distribution transformer monitor deployment forecast by driver

There may be a case for additional visibility access for other targeted risks or opportunities such as improving public safety, repex and augex avoidance or broader operational efficiency, however these drivers have not informed this LVVA access case.

In line with section 5.3.1, this investment also proposes continued scaled access to analytics platforms to support the realisation of the benefits from this visibility data. This includes operating a DVMS.

Quantified Costs

Table 12 – Approach for quantifying LVVA costs

Cost Component	Category	Quantification Approach
Smart Meter data procurement	opex	Blended average costs based on existing smart meter data trials with two metering data providers (Intellihub and PlusES). We have assumed a cost reduction for scale. This blended average cost is $8.7 per meter based on real time data access (required for DVMS). We have not adjusted for price increases.
Analytics Platforms	opex	We are trialling two LV analytics platforms and based on these we have used an average of their pricing models scaled to the number of meters we plan to access data from. We have not adjusted for price increases.
Distribution Transformer Monitor Data Costs	opex	This is based on sim card charges for data streams from Distribution Transformer Monitors. This is based on a $10/month/per monitor charge. Note the capital costs of DTX Monitoring is captured in 6.3.2.

Quantified Benefits

Table 13 – Approach for quantifying LVVA benefits

Use Case	VaDER or other Benefits	Share of Total Value Stack	Our Approach to Quantification
Tariff Reform	CECV	0.2%	This benefit is explicitly modelled through our hosting capacity simulator. The curtailment alleviation profile from is the difference between our BAU case and the Tariff Reform case. 100% of the tariff reform benefit is attributed to LVVA as load profile analytics is the dominant aspect of designing tariffs.
Phase Balancing	CECV	4%	This benefit is explicitly modelled through our hosting capacity simulator. The curtailment alleviation profile is the difference between our Tariff Reform case and the Phase Balancing case. 50% of the modelled benefits of Phase Balancing is attributed to LVVA and 50% is attributed to the cost of the truck roll and crew time (see section 6.3.4)
Tap Optimisation	CECV	10%	This benefit is explicitly modelled through our hosting capacity simulator. The curtailment alleviation profile is the difference between our Phase Balancing case and the Tap Optimisation case. 50% of the modelled benefits of Phase Balancing is attributed to LVVA and 50% is attributed to the cost of the truck roll and crew time (see section 6.3.4)

Use Case	VaDER or other Benefits	Share of Total Value Stack	Our Approach to Quantification
DVMS	CECV	8%	This benefit is explicitly modelled through our hosting capacity simulator via the implementation of a DVMS simulator routine. The curtailment alleviation profile is the difference between our Tap Optimised case and the DVMS case. 100% of the modelled benefits of operating the DVMS is attributed to LVVA as this functionality as there are no other significant costs beyond data access and the analytic platform costed under LVVA.
Dynamic Operating Envelopes (DOESs)	CECV	15%	A detailed description of our approach to calculating DOE value is provided in Section 6.3.6. 50% of the modelled benefits of DOEs is attributed to LVVA as it is critical to calculation of DOEs and 50% is attributed to the cost of DERMS and supporting systems to communicate the DOEs to customers (see section 6.3.6)
DER Detection and Validation	CECV	1%	DER detection and validation allow improvement to our records as well as DER forecasting process. It allows detection of the location and size of Solar, Batteries, EVs to improve our locational specific forecasts and actions. It also allows continued AS4777 and static limit compliance assessment which can inform OEMs and installers who are not configuring We have conservatively modelled all these benefits as a 1% improvement to overall curtailment.
LV Augmentation Scoping		13%	Our forecast DER related LV augmentation forecast as covered in 6.3.5 is treated as a volumetric forecast rather than locking in augmentation at specific sites pre-25-29 LVVA will be critical to ensuring this forecast augmentation expenditure is directed at the most appropriate sites from timing and locational perspective. As such, 10% of the overall benefit derived from LV augmentation is attributed to LVVA for assisting accurate scoping.
Reduced PQ Monitoring	Opex saving	2%	Our LVVA trials show that 30-40% of PQ monitoring is being avoided with a broad sample of data. This will increase commensurate to LVVA increase. The modelled savings is $1600 per LV monitoring truck roll avoided with an expected 825 avoided truck rolls across FY25-29.
Conservation Voltage Reduction	SRMC	27%	Internal testing of voltage reduction demonstrated CVR factors (% change in energy per % change in voltage) of between 0.6 (summer) - 0.8 (winter). We have assumed a 0.6 CVR factor across the year multiplied by an assumed average voltage reduction achieved by operating the DVMS and static transformer tap optimisation programs. We have valued this using the Oakley Greenwood Short Run Marginal cost forecast undertaken for establishing the CECV. This is assumed

Use Case	VaDER or other Benefits	Share of Total Value Stack	Our Approach to Quantification
			to be the most current and best forecast of avoided marginal generation value.
Electricity Theft Detection		1%	Internal studies (refer to Endeavour Energy loss factor report) estimate that 0.7% of LV revenue is attributable to theft. We have assumed that we would be able to detect theft only at LV networks where we have transformer monitors in combination with the smart meter interval data. Further we have assumed a 30% success rate in identifying the exact theft customer and enforcing rectification. The revenue benefit is the above factors scaled on our annual revenue from residential customers.
Safety	Statistical Value of Life	7%	We have calculated benefits based on the reduction in probability of consequence associated with broken neutrals causing shocks leading to death or major injury. The probability of consequence of death is assumed to be 1 in 50 years based on NSW public safety working group. The cost of consequence has been derived in reference to our GNV 1119 (Quantitative Assessment of WHS Risks) [5] The risk reduction benefit is scaled based on our overall LVVA % visibility.
Unserved Energy (Reliability)	VCR	10%	For this benefit we have leveraged publicly available consultant studies on quantifying the benefits of Victorian AMI rollouts. We have applied the reliability benefits from Deloitte's CBA [6], which had the most conservative estimate of Unserved Energy benefit from AMI data by a factor of >3.5. We then applied the average expected % SAIDI improvement benefit across the Victorian networks and applied this to our current average SAIDI performance to determine a minutes of unserved energy improvement This is then used to quantify the VCR benefit using our total annual residential energy consumption data (from our latest RIN) and our average residential feeder VCR (internal annual calculation).

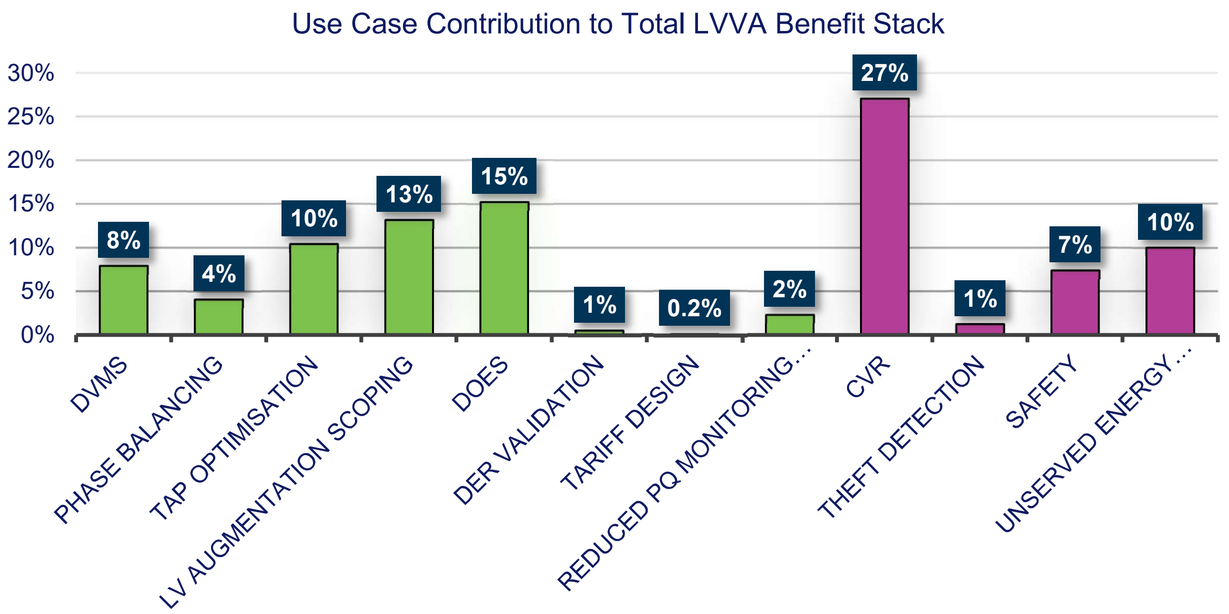

Figure 42 – Per use case contribution to total LVVA benefits (VaDER benefits green, other benefits red)

Net Present Value

This investment is NPV positive at +$14.0m with a cost benefit ratio of 1.9.

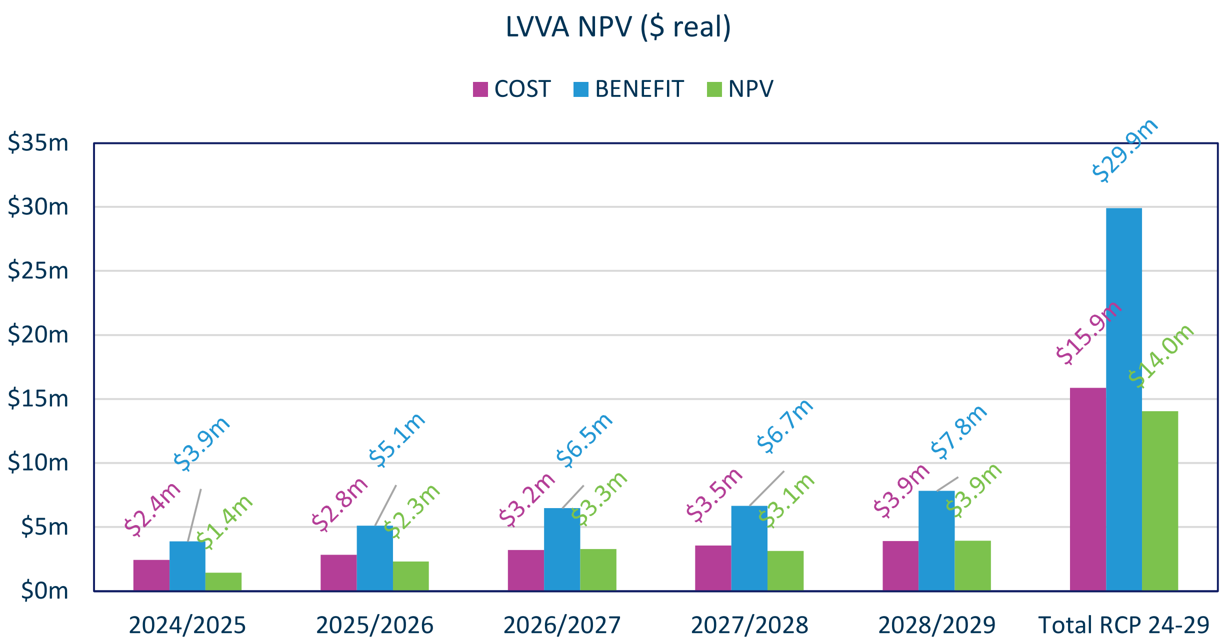

Figure 43 – LV Visibility NPV

6.3.2 Distribution Transformer Monitoring

Investment Strategy

The investment strategy for the deployment of Distribution Transformer Monitoring is covered in 6.3.1.

Quantified Costs

Table 14 – Transformer monitoring costs

Cost Component	Category	Quantification Approach
Installed Monitor Costs	Capex	The installed Distribution Transformer monitor cost is $3350-3500 per monitor based on our current deployments. For this case we have reduced this to $3200 per monitor accounting for volume cost reduction and improved installation efficiency.
Data Charges	opex	The recurrent annual opex and API costs are included in the LVVA costs

Quantified Benefits

Table 15 – Transformer monitoring benefits

Use Case	VaDER or other Benefit	Share of Total Value Stack	Our Approach to Quantification
LVVA	Refer to LVVA Benefit Stack	100%	The value of DTX monitoring is derived as a 30% share of the overall LVVA benefits. This is due to our blended visibility strategy and the mutual benefit two complementary data sources provide.

Net Present Value

This investment is NPV positive at +$3.9m with a cost benefit ratio of 1.4.

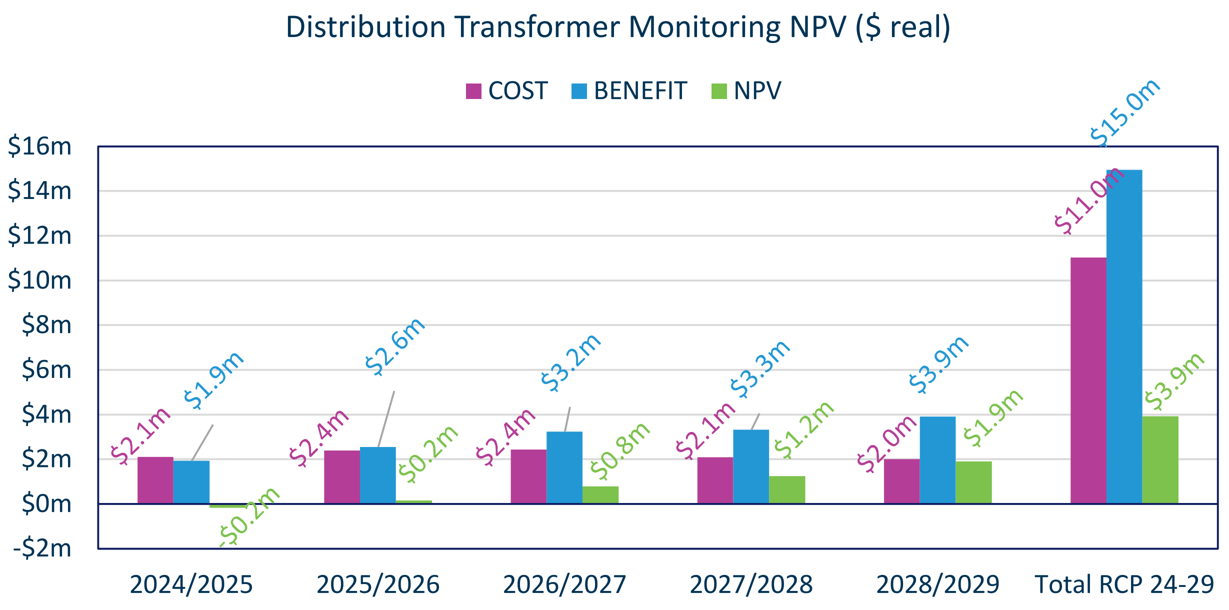

Figure 44 – Transformer Monitoring NPV

6.3.3 Hot Water Solar Soaking (Off Peak Plus Rollout)

Investment Strategy

This investment seeks to accelerate the natural churn of meter replacements, focussed on customers with hot water systems. This is to accelerate the solar soaking benefit and contribute to avoiding investment in replacement ripple control systems in Zone Substations.

The investment strategy seeks to contribute to accelerating smart meter rollouts to customers with hot water systems such that all these customers are on smart meter hot water control by end of FY27 rather than the expected projected natural churn trend of 100% smart meters by 2036 (BAU Case) or 100% smart meters by 2030 (as proposed under the AEMC's Power of Choice Metering review).

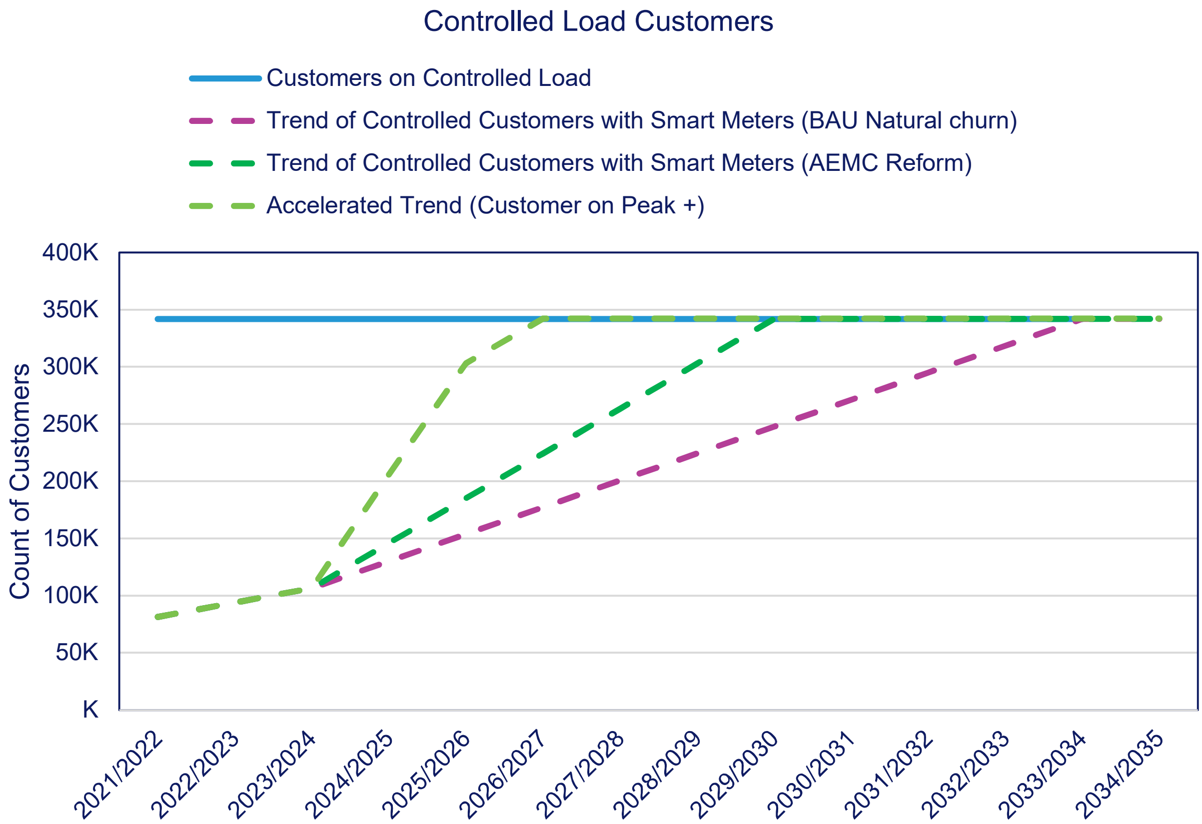

Figure 45 – Controlled load customers with smart meters trend

Quantified Costs

Table 16 – Approach for quantifying the cost of smart meter incentive payments

Cost Component	Category	Quantification Approach
Smart Meter installation Incentive Payment	opex	We undertook an open market tender process for the Off Peak + project in Albion Park Zone Substation. An incentive rate of $120 per meter exchange was agreed and this is expected to be relevant for future deployments.

Quantified Benefits

Table 17 – Hot water solar soaking benefits

Use Case	VaDER or other Benefit	Share of Total Value Stack	Our Approach to Quantification
Avoided Curtailment from Hot Water Solar Soaking	CECV	7%	Modelled through hosting capacity simulation by adjusting the controlled customer underlying load profile from their existing off peak heating profile to a profile with solar soaking component. We then look at incremental change in curtailment that results.
Avoided investment in replacement ripple control systems	Capex deferral	72%	Assumes we target the Off Peak Plus incentive program where there is a network investment deferral benefit. That is avoiding a replacement end of life ripple control system or network alternative (time clocks). We calculate the present value of the annual deferral value of this investment over a 30-year asset life period.
Avoided Cold Water Calls	opex avoidance	20%	Avoided EMSO truck rolls to attend cold water calls (taken over by meter provider). Scaled based on acceleration proportion and
Avoided Customer Relay replacements	Capex avoidance	1%	Avoided customer ripple control relays where this is determined to be the issue by the attending EMSO. Yet to be quantified.
Acceleration of Tariff Take-up	CECV / LRMC	Not yet quantified	Supports faster cost reflective tariff adoption above natural meter churn rate. Interval metering is required for cost reflective tariffs. Yet to be quantified.

Net Present Value

This investment is NPV positive at +$1.1m with a cost benefit ratio of 1.2.

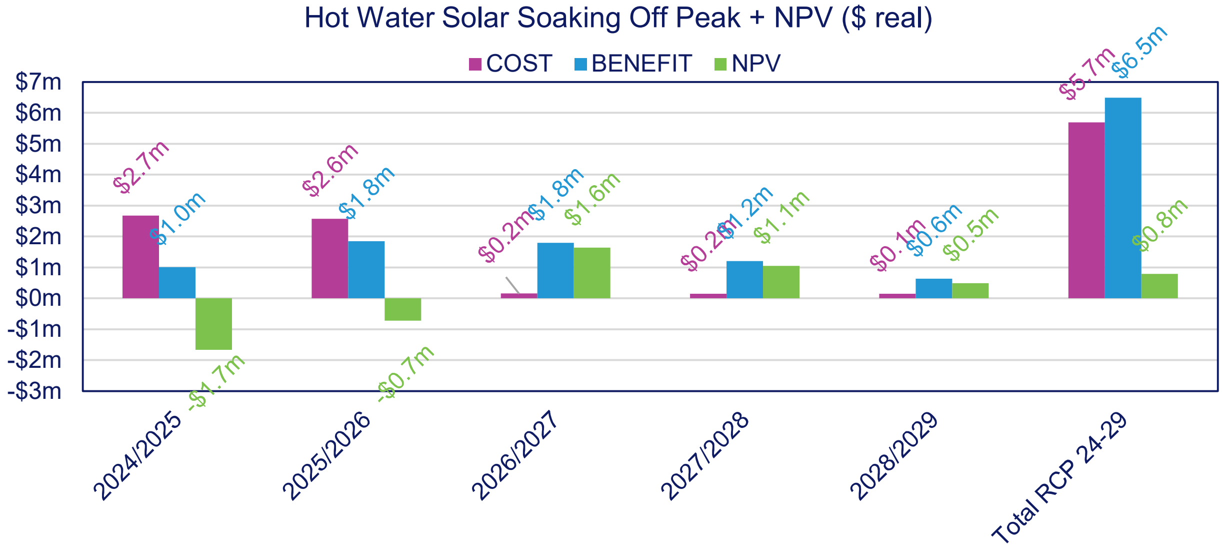

Figure 46 – Hot Water Solar Soaking NPV

6.3.4 Distribution Transformer Tap Optimisation and Phase Balancing

Investment Strategy

We have included a constrained forward forecast of Tap Changing and Phase Balancing in our Hosting Capacity Simulation tool as enabled by LVVA. Tap Changing activities related to solar have increased dramatically since 2015 where some 223 tap changes were undertaken and peak in 2019 at 728 tap changes. In 2020 and 2021 we were limited in our ability to complete tap changes and phase balancing due to covid and flood impacts.

Our forecast for FY23 onwards including across FY25-29 is an increase of some 25% above 2019 levels commensurate to improved LVVA. However, we have constrained our simulation to no more than 1000 sites per year as an increase beyond this is likely not feasible with current resourcing levels.

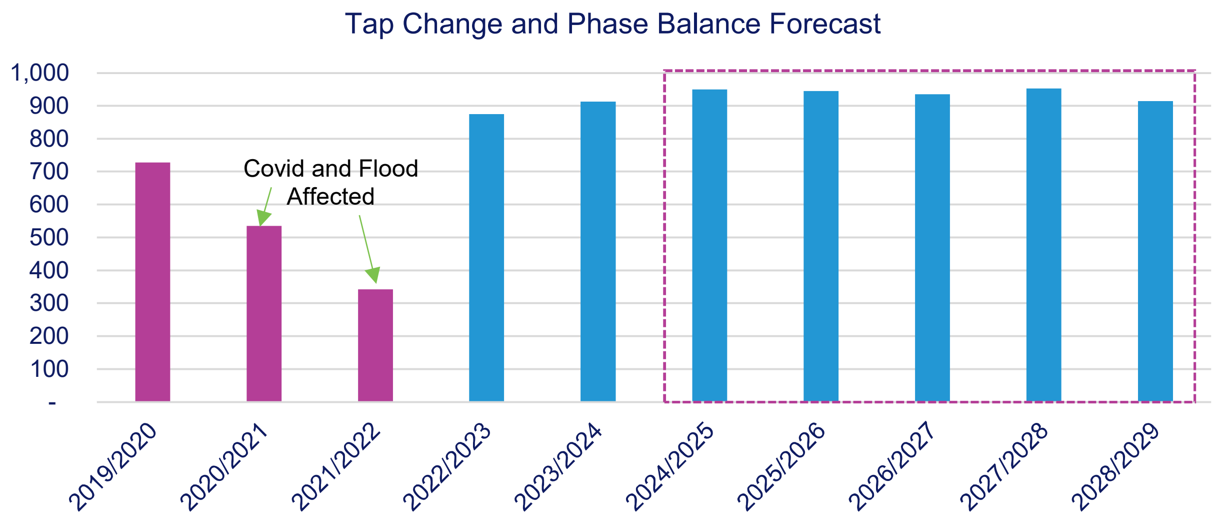

Figure 47 – Tap change program actuals and forecast

Quantified Costs

Table 18 – Quantifying cost of truck rolls

Cost Component	Category	Quantification Approach
Truck roll costs	Opex	Based on historic average truck roll costs per tap change and the simulated number of tap changes and phase balance activities required per year The assumed average rate per site is $1,000

Quantified Benefits

Table 19 – Tap optimisation benefits

Use Case	VaDER or other Benefit	Share of Total Value Stack	Our Approach to Quantification
Tap optimisation and Phase Balancing	CECV	50%	This benefit is explicitly modelled through our hosting capacity simulator (refer 6.3.1). 50% of the modelled benefits of Tap Changing and Phase Balancing is attributed to LVVA and 50% and 50% is attributed to the Tap Changing and Phase Balancing Truck Roll Costs.

Net Present Value

This investment is NPV positive at +$3.1m with a cost benefit ratio of 1.7.

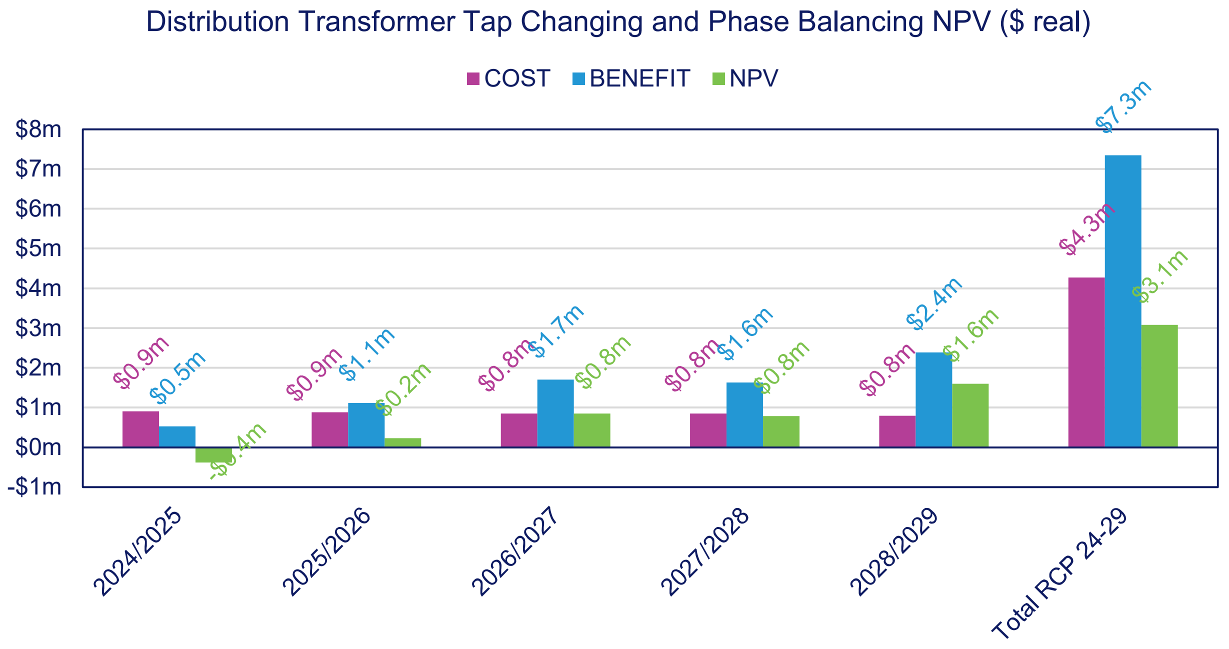

Figure 48 – Transformer tapping NPV

6.3.5 Network Investment

Investment Strategy

Our hosting capacity simulation tool exports the remaining forecast curtailment and CECV after the modelled reductions associated with the operational actions in our DER Integration Plan. We utilise this remaining modelled curtailment per Distribution Transformer (LV network) and undertake an NPV test for network augmentation.
Our augmentation strategy is to consider 3 augmentation option types/categories for which technical tests and criteria are applied to select the likely best solution for each LV network (Distribution Transformer). The associated costs of this selected solution are then tested against the quantifiable VaDER benefits. This is summarised as follows:

Table 20 – LV Augmentation Options Breakdown

Option	Category	Benefits
Tap Limited Distribution Transformer Tank Replacement	Selected as best option where the transformer is of a legacy type without buck taps	CECV, Avoided future replacement
LV STATCOM	Selected as best option voltage only problem where X/R ratio is sufficient for LV STATCOM to be effective	CECV
Network LV Battery **Or** **Major LV Augmentation**	Selected as best option voltage only problem but X/R ratio is low (STATCOM not effective) and / or the DTX is overloaded	Major Augmentation: CECV & VCR LV Battery: CECV, VCR & LRMC (Assumed 50:50 split)

Quantified Costs

Table 21 – LV Augmentation Costs

Option	Assumed Cost (Installed)	Comments
Tap Limited Distribution Transformer Tank Replacement	$15,000	Based on F&E Distribution Transformer tank replacement average costs
LV STATCOM	$30,000	Based on forecast hardware costs + typical installation costs from previous STATCOM installations
Network LV Battery **Or** **Major LV Augmentation**	$90,000	Battery costs based on quotes and assumed installation costs under our battery trials. Major augment assumed either a significant run of LV amplification or splitting the LV (installation of new Distribution Transformer and reconfiguration of LV circuits). These two options have similar costs profiles and technical feasibility as solutions and therefore we have assumed a 50:50 split.

Quantified Benefits

Table 22 – LV augmentation benefits

Use Case	VaDER or other Benefit	Our Approach to Quantification
Hosting Capacity	CECV	Summarised Annual kWh curtailment and associated CECV from time series simulation model is exported into Spreadsheet NPV model per Distribution Transformer. The 15-year present value of the CECV for each Distribution Transformer is tested against the relevant technically correct solution cost for each year in FY25-29.
Reliability	VCR	In addition to the above, where a transformer is forecast to be overloaded (forward or reverse), we have modelled a Distribution Transformer Outage affecting those connected customers (specific to each Distribution Transformer). Our average LV transformer outage is 4.7 hours. We have conservatively assumed that outage occurs during the daytime with minimum underlying customer demand (average of 0.8kW per customer gross of solar where applicable). This is then valued using a VCR of $38/kWh. The present value of this modelled outage cost at the relevant year is added to the benefit stack if applicable to the specific transformer.
Avoided Peak Demand Investment	Network LRMC	In addition to the above, we have assumed 50% of major augments are network batteries. Batteries can peak shave (reduce peak demand. The assumed battery parameters are 50kW / 2hr and able to offset the associated peak demand at the LV level. We then apply the global LV level network Long Run Marginal Cost ($96) to quantify the value and take the present value of this recurrent annual benefit for the usable life of the battery (15-year). Given only 50% of major augments are assumed network batteries only 50% of the LRMC benefit is counted to each Distribution Transformer benefit stack for which a major augment is the correct technical solution for the purposes of the NPV test.
Avoided Future Distribution Transformer Replacement	Repex deferral	Where the identified correct technical solution is replacing a tap limited Distribution Transformer, the avoided future cost of replacing this transformer is captured. The average age of the fleet of tap limited Distribution Transformers is currently 45 years old with an assumed failure age of 55 years. The forward replacement cost is converted to present value and added to the benefit stack for the NPV test.

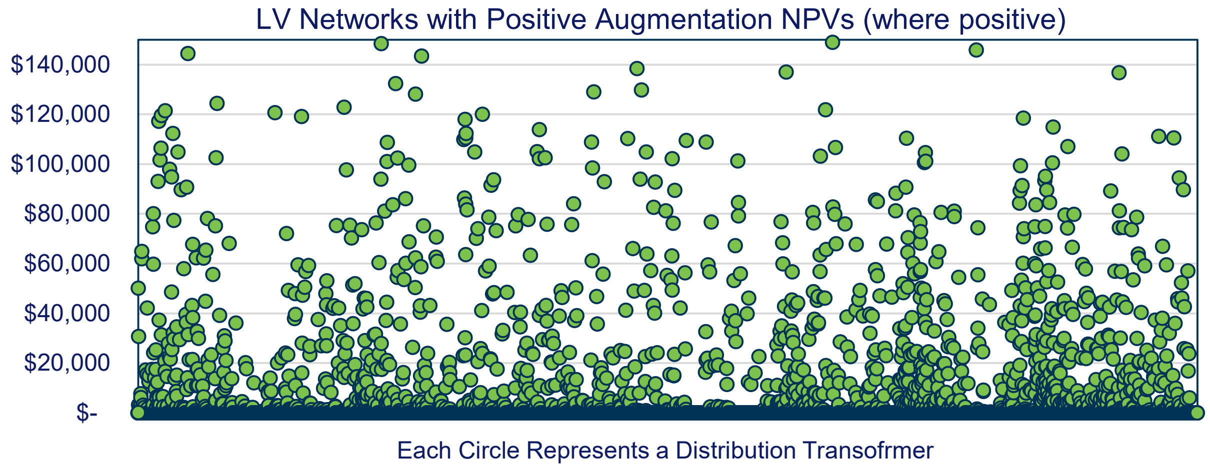

Figure 49 – Results of LV Augmentation NPV test per distribution transformer

Net Present Value

Based on this NPV analysis:

- 1140 Tap Limited Distribution Transformer Tank replacements are forecast to be justified
- 240 LV STATCOMs are forecast to be justified
- 50 LV Batteries are forecast to be justified
- 50 Major LV Augmentations are justified

It should be noted that this forecast should be interpreted as estimating the global augmentation capex which is likely justifiable rather than committing to augmenting specific sites (without consideration to monitoring actual take-up). This analysis will continue to be re-run to ensure that these investments are targeted at the highest value locations as locational specific uptake and timing dictates.

This overall investment is NPV positive at +$31.9m with a cost benefit ratio of 2.1.

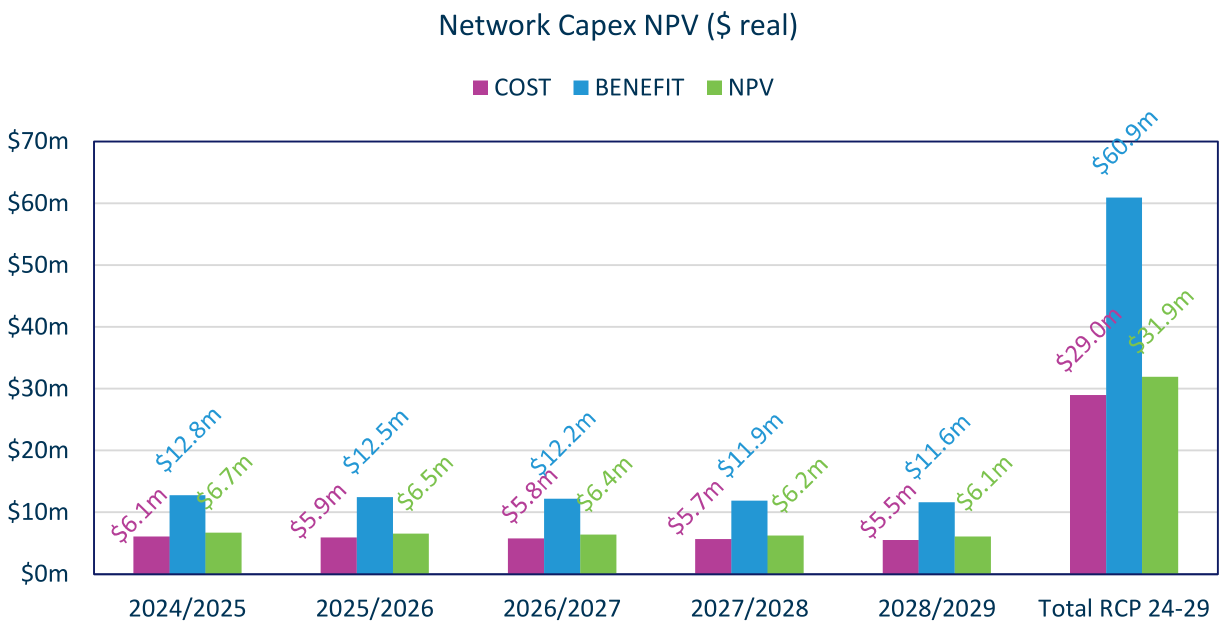

Figure 50 – LV augmentation NPV

6.3.6 DSO Systems

Investment Strategy

To achieve end to end DOEs, investment in the following infrastructure is required:

- LVVA: This supports DOEs in combination with DERMS (covered under 6.3.1).
- DERMS: This includes an IEEE 2030.5 utility server, LVVA integration, customer portal integrations and ADMS integration.
- Customer Portals: Portal and app for customers to sign up to flexible exports / DOEs and installers to commission devices into the flexible export program.

Quantified Costs

Table 23 – DSO systems costs

Cost Component	Category	Quantification Approach
DERMS	capex	Quantified based on DERMS quotes
Customer Portal and Systems Integrations	capex	Estimated based on experience with ADMS projects and consultation with ADMS/IT.

Quantified Benefits

We have modelled the effect and benefits of DOEs on unlocking solar exports using a time series desktop model (workflow), The model uses time series irradiance data to model a PV system, time series underlying load (as per our simulation models) to calculate an average solar customer net export. This export is then limited to 5kW as well as unconstrained. The delta between the energy exported is then the alleviation profile and valued using the time series CECV in the same workflow. This is explained in more detail in Hosting Capacity Modelling Basis of Preparation (Attachment 1) and visualised in Figure 51.

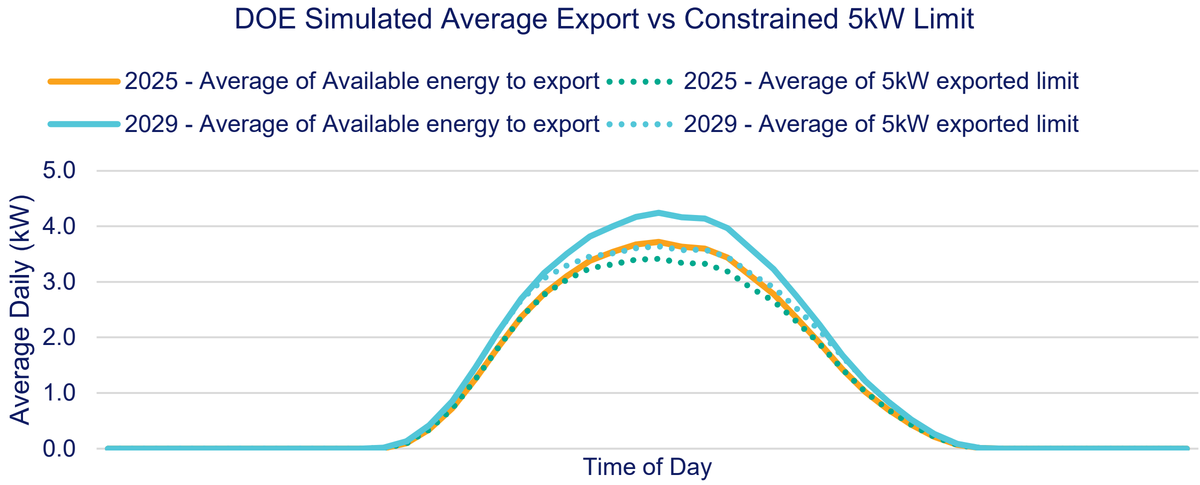

Figure 51 – DOE Released Energy (average profile)

DOE take up rates and other factors considered are explained in

Table 24 below.

Table 24 – DSO systems benefits

Use Case	VaDER or other Benefit	Share of Total Value Stack	Our Approach to Quantification
Flexible Exports	CECV	100%	The alleviation profile for DOEs for the average solar system was calculated as per above workflow. We then moderated by the following factors across FY25-29: • Customer adoption / take-up rates which commences at 50% in FY25 and ends at 90% in FY29 • Assume time that the DOE curtails to 0 or minimum exports. This commences at 2% of time (as publicised by SAPN "Analysis shows the flexible export limits will typically be at 10kW for 98% of the time" [7]) and is assumed to increase by 1% per annum as congestion increases. • Generalised DOE accuracy factor. This moderates the overall benefit by assuming that the DOE window is only as accurate as the LVVA average visibility supports. The total benefits of DOEs is shared as follows: 45% to LVVA 45% to Investment in DERMS 10% to IT Business Case for overheads associated with the various integrations.
System Security	VCR	Not Quantified	It is acknowledged that over time DOE capability aid system security by being an effective mechanism for implementing minimum demand backstop under AEMO direction. This has not been quantified at this time due to the complexity of estimating the benefit.

Net Present Value

This investment is NPV positive at +$2.1m with a cost benefit ratio of 1.5.

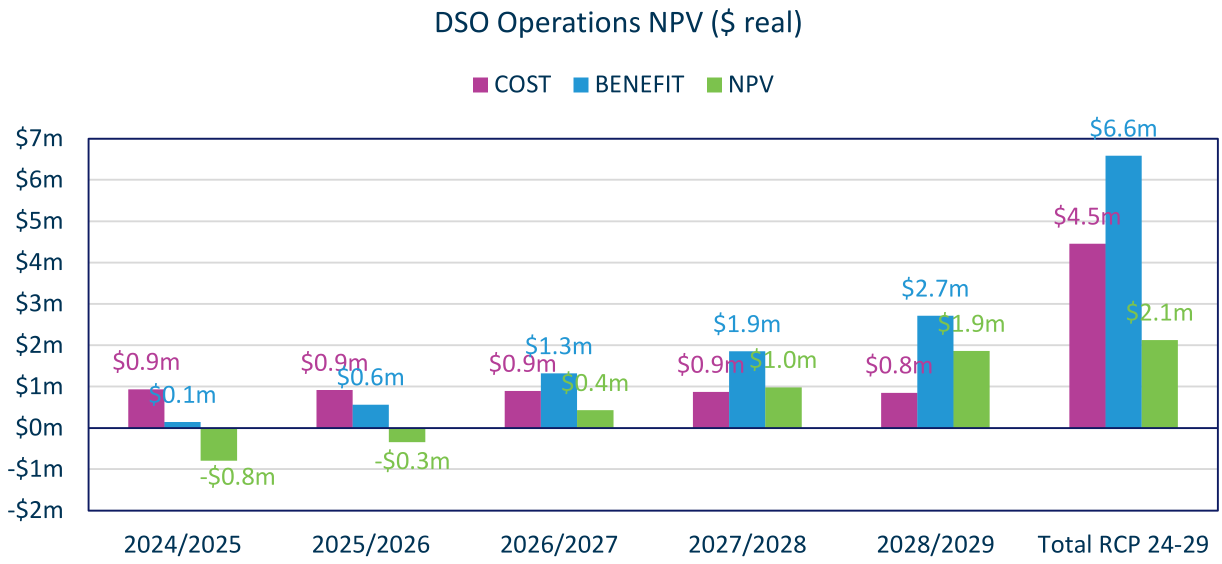

Figure 52 – DSO systems NPV

6.4 Summary

6.4.1 Investment Summary

Our proposed investment totals $81.2m across system capex, opex and ICT capex. A breakdown of this investment by category is provided below.

Table 25 – Investment Summary (Real $)

Investment Category	FY25	FY26	FY27	FY28	FY29	Total (RCP24-29)
opex	$6.9 m	$7.3 m	$5.1 m	$5.6 m	$6.1 m	**$31.0 m**
Network capex	$8.8 m	$9.2 m	$9.3 m	$8.9 m	$8.9 m	**$45.1 m**
ICT capex	$1.0 m	$1.0 m	$1.0 m	$1.0 m	$1.0 m	**$5.0 m**
Total	**$16.7 m**	**$17.5 m**	**$15.4 m**	**$15.6 m**	**$16.0 m**	**$81.2 m**

6.4.2 Opex Step Change

Our opex investment proposal over RCP 24-29 totals $31m, of which represents a step change of $24.2m from current investment levels. This step change is primarily due to LVVA and Off Peak Plus (hot water solar soaking) investments.

Table 26 – Opex step change (Real $)

Investment Category	FY25	FY26	FY27	FY28	FY29	Total (RCP24-29)
Opex (step change)	$5.5 m	$5.9 m	$3.8 m	$4.3 m	$4.8 m	**$24.2 m**

6.4.3 Net Present Value

Our overall proposal has a total of $126m in present benefits for an NPV of $56m. This overall program has a cost-benefit ratio of 1.8.

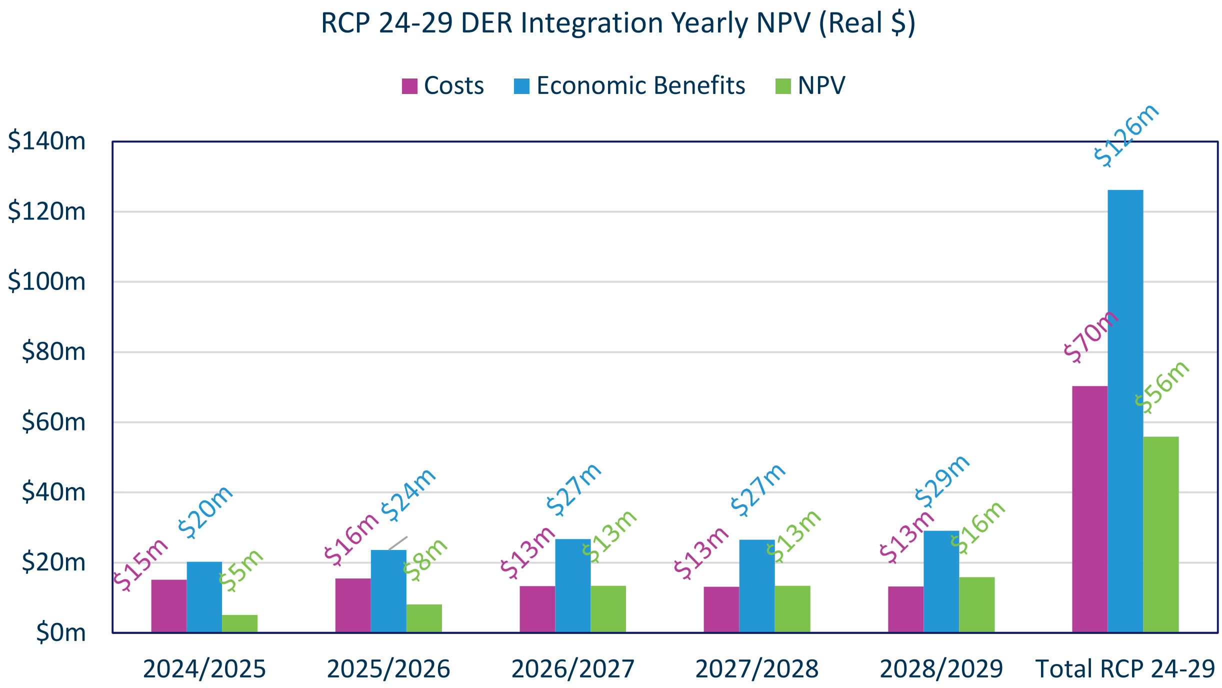

Figure 53 – Total NPV

The present costs, benefits and NPV per project under this business case is summarised in Figure 54 below. Note that customer call investigations are included in the overall costs however is not represented below as a project as it is an expected BAU obligation/activity of a network. It represents a forecast $2m across FY25-29.

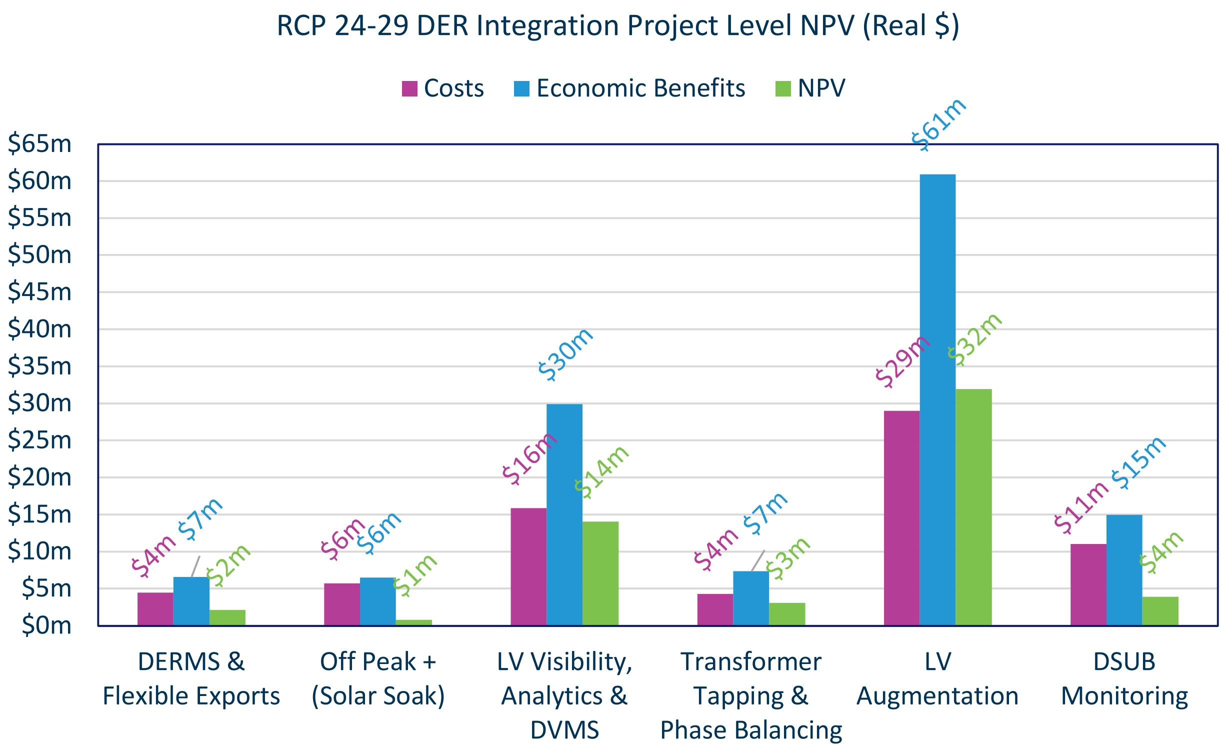

Figure 54 – Total NPV per project

Appendices

Appendix 1 – Endeavour Energy ‘Hosting Capacity Modelling – Basis of Preparation’ report.

Appendix 2 – Endeavour Energy ‘DER Expenditure Model V11.xlsx’.

References

[1] ESB 'DER Implementation Plan 3-year Horizon', December 2021, Accessed at: https://www.energy.gov.au/sites/default/files/2021-12/Attachment%20A%20-%20DER%20Implementation%20Plan%20-%20Three%20Year%20Horizon%20-%20December%202021.pdf

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[4] KPMG, Slide Deck: 'Endeavour Energy approach to valuing DER – Environmental Benefits and Avoided Generation Costs' (Internal)

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[7] SAPN Website, Flexible Exports, with reference to " Flexible Export limit" section https://www.sapowernetworks.com.au/industry/flexible-exports/fixed-v-flexible/

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Endeavour Energy

DER INTEGRATION HOSTING CAPACITY MODEL DOCUMENTATION

Endeavour Energy

Regulatory Proposal
2024-2029

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Glossary

AEMO	Australian Energy Market Operator
APQRC	Australian Power Quality and Reliability Centre
CCP	customer connection point
CL	controlled load
DVMS	dynamic voltage management system
EE	Endeavour Energy
ISP	AEMO's Integrated System Plan
VaDER	Value of Distributed Energy Resources
CECV	Customer Export Curtailment Value
DER	distributed energy resources
DOE	dynamic operating envelope
EV	electric vehicle
GIS	geographic information system
HCM	hosting capacity modelling
HV	high voltage
kW	kilowatt
kWh	kilowatt-hour
LGA	local government area
LV	low voltage
PV	photovoltaic
NIEIR	National Institute of Economic and Industry Research
NMI	national meter identifier
TOU	time of use
UOW	University of Wollongong
VAR	volt-ampere reactive
VCR	value of customer reliability

1. Introduction

1.1 Document Purpose

The purpose of this document is to explain the inputs, workings, assumptions and outputs that were used for Endeavour Energy's Low Voltage Hosting Capacity Modelling (HCM).

1.2 Context

Endeavour Energy's HCM was carried out for the 2024-2029 regulatory assessment period to quantify the network constraints and resultant impacts to customers of increasing levels of Distributed Energy Resources (DER) on the network. Specifically, the study considered the rise of residential Photovoltaic (PV) systems, Electric Vehicles (EVs) and Batteries.

The key constraints of interest included:

1. **DER Inverter Curtailment:** energy curtailed as per AS4777 trip settings and response modes
2. **Distribution Transformer Capacity:** Transformer loading kW, maximum and minimum demand voltages
3. **High-Voltage Feeder Capacity:** High voltage feeder loading kVA

The above constraints were measured at a "baseline" level, that is, the scenario that would ensue without further intervention on the network. The modelling tool was then used to simulate several alleviation interventions to determine the value they provided to customers. This analysis was then used to inform the DER Integration Strategy and Business Case.

1.3 Our Approach to HCM

There are multiple approaches to simulating and assessing DER hosting capacity, or inversely quantifying the impacts of unconstrained DER uptake on the network. The Guidance notes that hosting capacity can be "deterministic or probabilistic and can be undertaken using a range of modelling and analysis methods."

Endeavour Energy has developed a LV simulation tool in partnership with researchers at the University of Wollongong's (UOW) Australian Power Quality and Reliability Centre (APQRC). The tool takes advantage of the open-source electrical power flow engine OpenDSS to run time-series power flow simulations.

The HCM utilises a DER forecast explored in Section 3.1 and focuses on modelling residential customers.

2. The Hosting Capacity Model

Figure 1 below demonstrates the flow of inputs into the simulation tool all the way through to the outputs that are used for the DER Integration Business Case. An interactive flowchart can be accessed here and aims to bring the viewer on the journey from inputs to final outputs, explaining each stage of the process. Within the document, each stage shown in the diagram below is detailed in Sections 3 - 8.

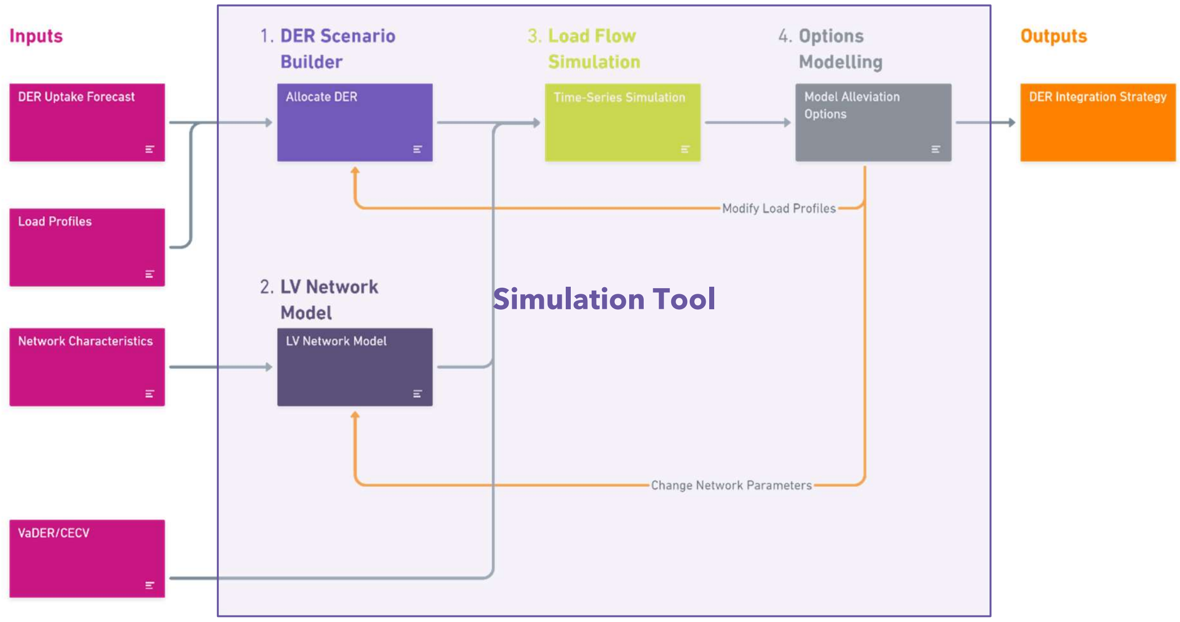


Figure 1 Inputs, Processing and Outputs of the Simulation Tool

2.1 Overview of the Simulation Tool

A high-level overview of the simulation tool is shown below in Figure 2 and is broken down into 4 key stages:

1. DER Scenario Builder
2. LV Network Model
3. Load Flow Simulation
4. Options Modelling

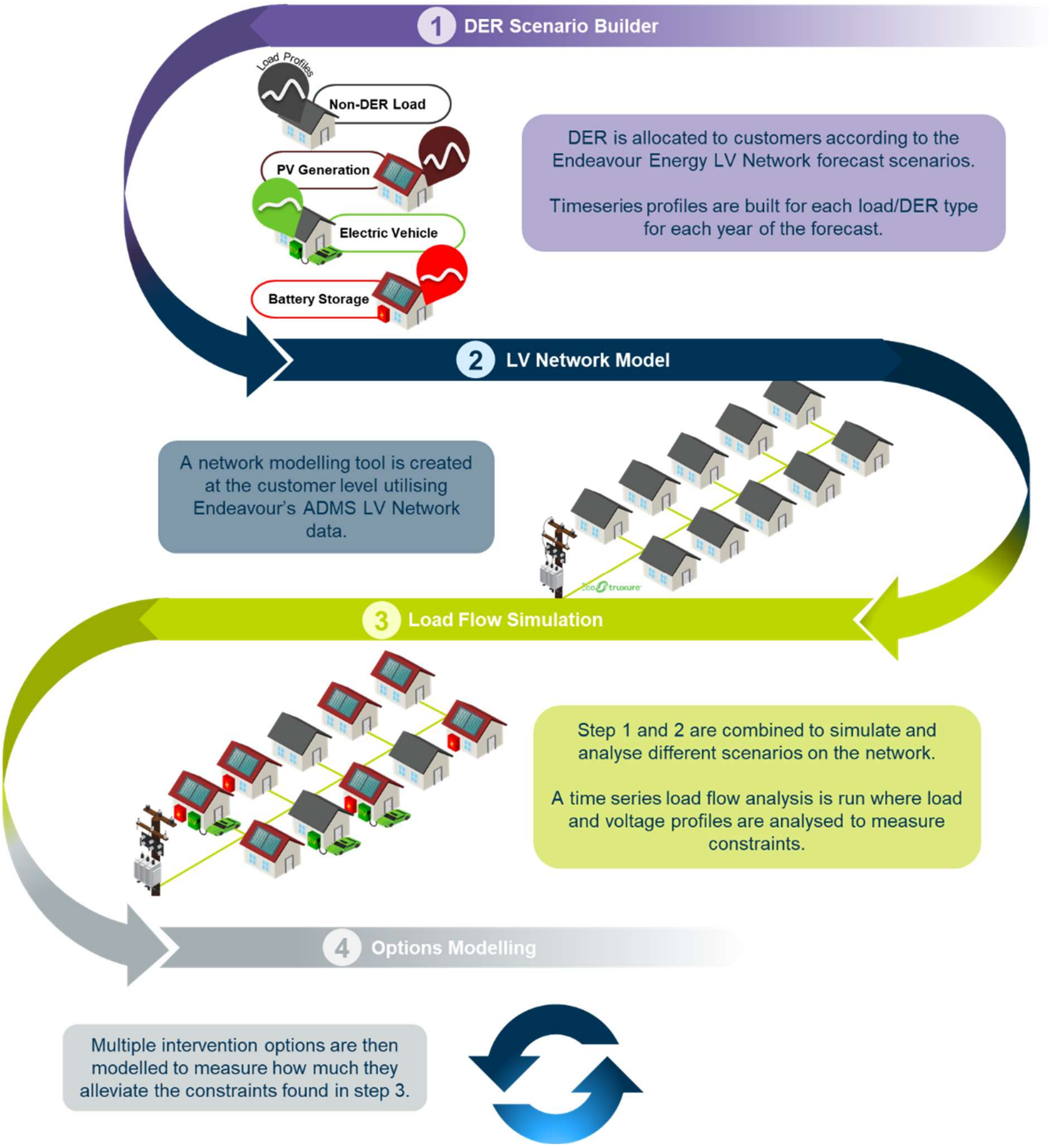


Figure 2 LV DER Integration Simulation Tool

3. Model Inputs

3.1 DER Uptake Forecast

The DER Uptake Forecast is a crucial input to the HCM. It defines the number of PV, EV and Battery Systems on the Endeavour Energy network at a low voltage feeder level.

Figure 3 shows a summary of the forecasted DER Penetration on the Endeavour Energy network over the next 20 years.

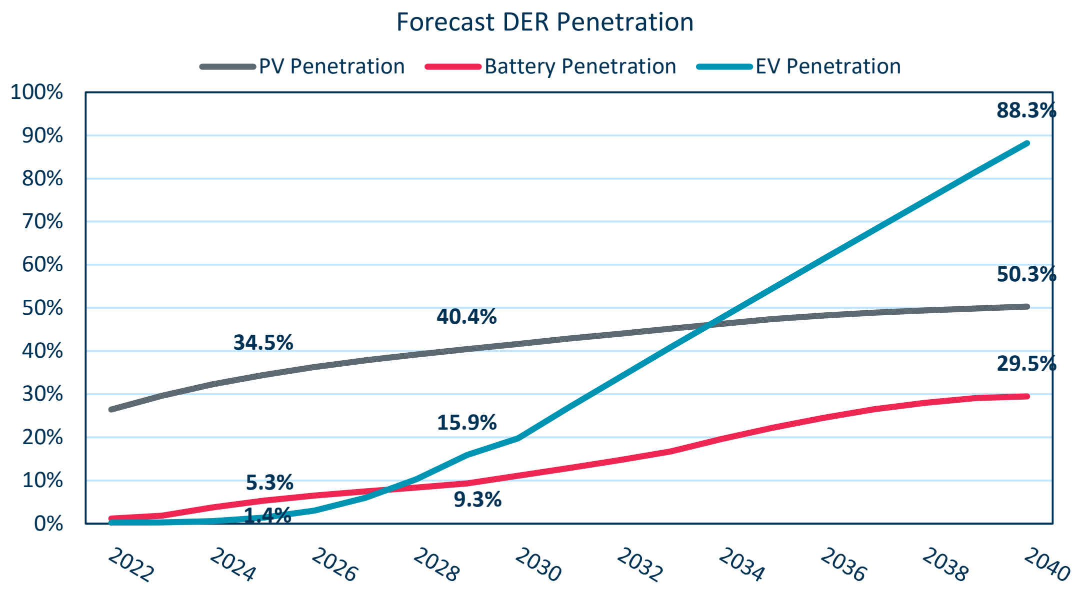


Figure 3 Step Change Scenario Forecast DER penetration as % of customers on EE Network

It should be noted that:

- EV penetration refers to connection point (customer penetration) rather than vehicle population penetration. As such, the connection point / customer penetration of EVs can exceed 100% due to multi vehicle households.
- All penetration values have been normalised to Endeavour Energy's projected customer growth.

3.1.1 How is the DER uptake forecast used?

The DER uptake forecast is used in the 'DER Scenario Builder' to help allocate DER systems to customers, explored further in Section 4.

3.1.2 How was the uptake forecast derived?

AEMO's 2022 ISP has coverage of four primary scenarios to span plausible energy transformation futures, namely, Slow Change, Progressive Change, Step Change and Hydrogen Superpower. The ISP is a long-term DER penetration forecast developed from credible sources and contextualised to Endeavour Energy's network and customer base.

Endeavour Energy requested input on AEMO's ISP scenarios from its Customer and Stakeholder Future Grid reference group. The reference group supported a focus on the Step Change scenario which is described as a "rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action". However, we will also consider book end scenarios to this central case, namely a high and low case as follows:

- **High Case:** Hydrogen Superpower
- **Central Case:** Step Change
- **Low Case:** Progressive Change

Currently the AER's work on Customer Export Curtailment Value (CECV) only considers the Step Change scenario in its modelling and this further supports our use of this scenario as the central case.

To forecast the expected DER uptake on the Endeavour Energy Network, we engaged the National Institute of Economic and Industry Research (NIEIR) to translate AEMOs ISP 2022 DER forecast scenarios for NSW to Endeavour Energy's network out to 2040 at the zone substation level, as detailed in Section 3.1.3. Based on customer numbers, we then mapped the uptake by zone substation to uptake by LV feeder.

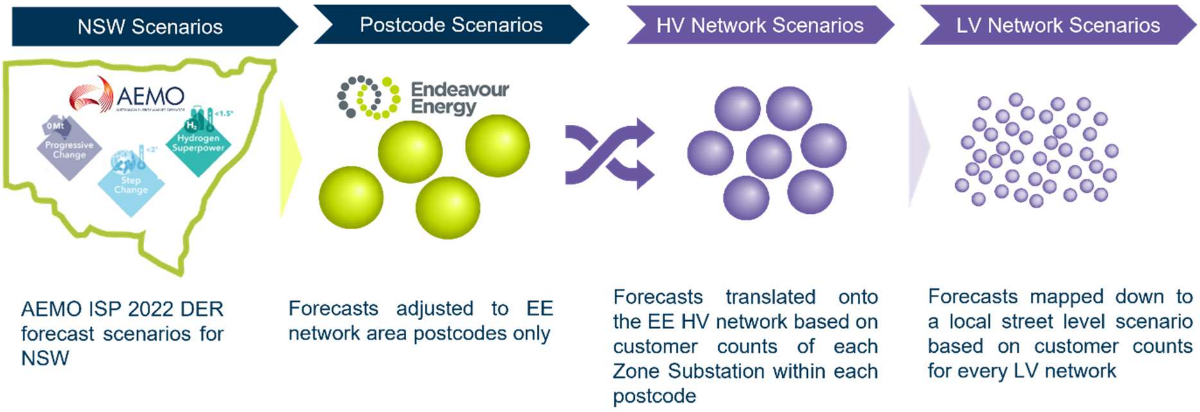


Figure 4 Translation of AEMO ISP Scenarios to Endeavour Network

The derivation of each DER type uptake is explained in detail within Section 3.1.3 - 3.2.5.

3.1.3 Regional mapping methodology

A key component to NIEIR's modelling was mapping the state based DER forecasts provided by the AEMO into zone substation based DER forecasts.

NIEIR achieved this down casting by breaking AEMO's state-based forecasts down into LGA's and post codes. Since any one LGA may have more than one DNSP supplying electricity customers within their area, a further mapping was created to determine the percentage of customers within that LGA that are connected to the Endeavour Energy network specifically. In this way, Endeavour Energy's 164 zone substations are mapped to Local Government Areas (LGAs) and their post codes.

Table 1 shows the list of LGAs that fall within Endeavour Energy's network, the percentage of customers within that LGA that are connected to the Endeavour Energy network and the count of zone substations in that LGA. For example, in the Central Coast LGA, only 10% of customers are served by Endeavour Energy. These customers would be connected to the 1 zone substations in that LGA.

The percentage of customers within an LGA that are connected to the EE network would then be used as a multiplier to the aforementioned LGA based DER forecast to understand the apportionment of DER to the Endeavour Energy network.

Table 1 Summary of LGA to Endeavour Zone Substation Mapping

LGA Name	% Customers within LGA connected to EE (%)	Number of ZS in LGA (no.)
Blacktown	100	59
Blue Mountains	100	18
Camden	100	25
Campbelltown	100	17
Canterbury-Bankstown	6.4	4
Central Coast	0.1	1
Cumberland	67.5	30
Fairfield	100	35
Goulburn Mulwaree	12.6	4
Hawkesbury	99.5	20
Hornsby	19.3	15
Kiama	100	8
Lithgow	98.4	13
Liverpool	99.1	39
Mid-Western Regional	42.5	3
Oberon	6.6	5
Parramatta	73	32
Penrith	100	37
Ryde	24.2	2
Shellharbour	100	13
Shoalhaven	99.7	20
Sutherland Shire	0.1	1
The Hills Shire	80.4	38
Wingecarribee	100	19
Wollondilly	100	36
Wollongong	100	30

3.1.4 Solar PV uptake

NIEIR pro ratas AEMO's NSW solar PV forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future.

AEMO's inputs and assumptions workbook provided estimates by State from 2021-22 to 2049-50 by scenario for the following:

- rooftop PV capacity measured in MW; and
- rooftop PV energy measured in GWh.

Given estimates of generation and capacity installed, capacity factors could be calculated which were between 13 and 14 per cent.

The AEMO scenario assumptions did not provide any information on customer numbers in total or customers by class nor any average capacity figures for new PV installations. Moreover, they did not provide any splits between solar only and solar battery for customers, capacity or generation for PV systems.

Using NIEIR's LGA to EE zone substation mapping, the key outputs provided by NIEIR included the following indicators by zone substation for rooftop PV from 2021-22 to 2039-40:

- Rooftop PV capacity measured in MW
- Rooftop PV generation measured in GWh
- Rooftop PV customers (number)
- Rooftop PV peak summer demand measured in MW (at 5:30 p.m.)

3.1.5 Electric Vehicles uptake

NIEIR developed a regional electric vehicle model which forecasts electric vehicle sales by 129 Local Government Areas (LGAs). The starting point of electric vehicle population was based on existing EV registrations mapped to Endeavour Energy postcodes. The EV uptake forecast was then determined based on a regional regression model that considers several demographic and social factors.

The key inputs to the regional electric vehicle model included:

- aggregated BEV and PHEV stock of electric vehicles for New South Wales
- aggregated BEV and PHEV annual energy (GWh) for New South Wales
- regional regression model

The regional regression model revealed that the most significant determinants of plug-in electric vehicle uptake include:

1. Household income – a non-linear specification was used that emphasises a higher concentration of registrations at higher levels of income
2. Availability of public transport – better access to public transport provides a greener substitute that suppresses demand for plug-in electric vehicles (and motor vehicles as a whole)
3. Tertiary education

The key outputs provided by NIEIR included:

- electric vehicle registrations by Endeavour zone substation split by private and business ownership
- annual energy (GWh) by Endeavour zone substation for residential, commercial, and industrial sections
- peak demand (MW) by Endeavour zone substation

The Regional Electric Vehicle Model describes the early to mid-market for adoption of electric vehicles. This phase of the market has stronger adoption of electric vehicles from higher income areas, as they have greater capacity to pay premium prices. However, once the price of newer electric vehicles comes down and the size of the market is large enough for a healthy second-hand car market, electric vehicles will become more accessible to more regions. Under higher electric vehicle penetration scenarios, electric vehicle registrations by region will converge toward the share of all motor vehicles registered.

3.1.6 Battery Uptake

NIEIR pro ratas AEMO's NSW battery forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future to translate the battery forecast.

AEMO's inputs and assumptions workbook provided estimates by State from 2021-22 to 2049-50 by scenario for the following:

- capacity measured in MW of embedded small-scale batteries; and
- storage capacity measured in MWh of embedded small-scale batteries.

AEMO's scenario assumptions did not provide any information on battery customer numbers. Customer and capacity figures were not provided by class or for combined PV/battery customers or battery only customers.

In order to generate zone substation forecasts consistent with the AEMO scenarios, NIEIR used average capacity assumptions to generate battery customer numbers.

NIEIR provided Endeavour Energy with the following indicators for small-scale batteries by zone substation from 2021-22 to 2039-40:

- battery capacity by class measured in MWh; and
- battery customers (number by class).

3.2 Load Profiles

The HCM ingests 4 characteristic profile types:

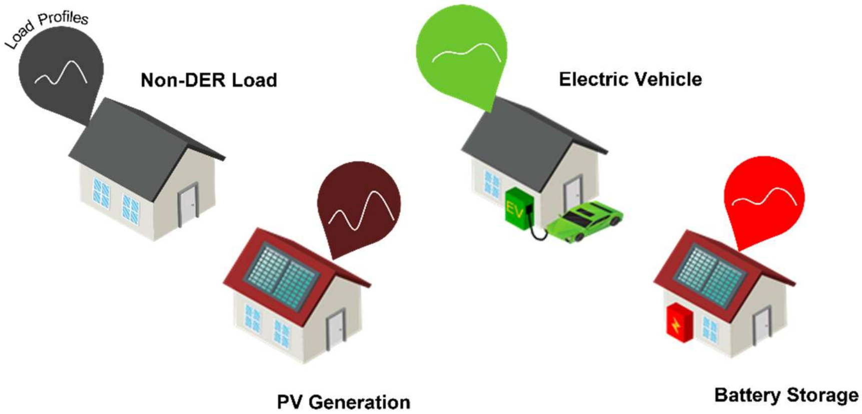


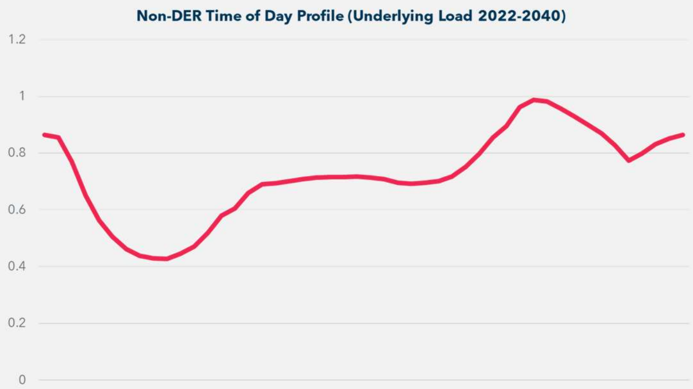
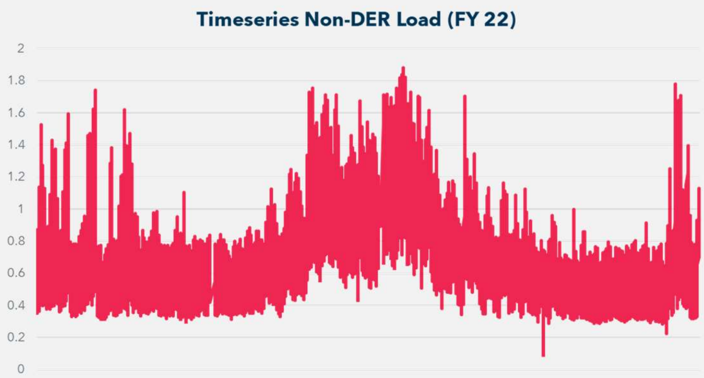
Figure 5 The 4 Characteristic Load Profile Types

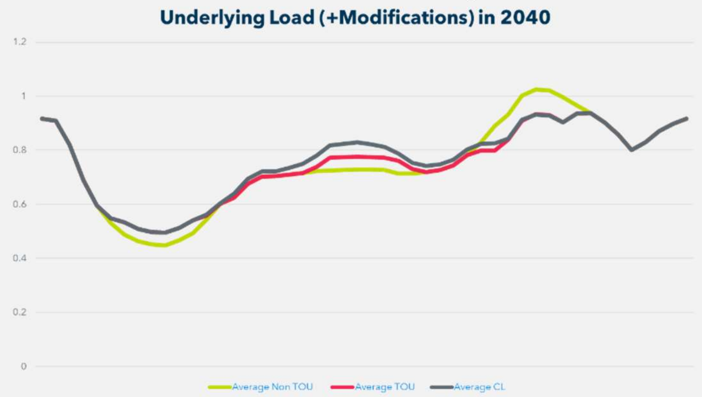
3.2.1 How are Load Profiles used within the Simulation Tool?

All profiles are 30-minute time-series load profiles, forecasted up to 20 years in the future. Each of the profiles are 'allocated' to customers within the simulation, as described in Section 4.

3.2.2 Non-DER (Underlying) Load Profile

Table 2 Non-DER (Underlying) Load Profile Details

Description	Non-DER Load is considered as the underlying consumption of each customer.  *Figure 6 Time of Day Average Non-DER Load (kW vs Time of Day)*  *Figure 7 Timeseries Non-DER Load (kW vs Datetime)*

Use	All customers are given the non-DER profile for all simulation years.
Source	5-minute time-series smart meter Intellihub Data (Snapshot at time) was aggregated to 30-minute intervals, taken from a population of ~10,000 meters, spread across the network. The data collected is from 10-07-2021 to 07-07-2022.
Data Preparation	Only data at 30-minute intervals are used for the model. The data from 10,000 meters are averaged, grouping by Date & Time. Albion Park's consumption data from smart meters was excluded from the average load profile due to the higher (& non-representative) penetration of controlled loads, resultant from the Off Peak Plus trial (as discussed in the DER Integration Strategy report).
Implied Assumptions	· The underlying load profile will remain constant for all simulation years · No diversity is present amongst customers. In future, more diverse 'characteristic' load profiles can be created and used within the model, however, greater visibility at the LV level is required.
Variations	Within the model, variants of the Non-DER profile are used to reflect the implementation of tariff reforms and controlled load tariff programs. The variants can be seen below and are explored in Section 7.  *Figure 8 Time of Day Average Non-DER Load + Modifications (kW vs Time of Day).* **Non TOU** = Current underlying load profile, **TOU** = Time of Use prosumer tariff activated, resulting in changed load consumption behaviour, **CL** = Greater uptake of Off Peak Plus program, i.e. higher levels of Controlled Loads (CL) on the network, causing a shift in load consumption behaviour.
Database Details	The Non-DER Load is stored as the 'smart_meter_load' in the table R_TIMESERIES_LOAD_UTC_NEW. A view also exists R_TIMESERIES_LOAD_AEDT_NEW with the timestamp converted from UTC to AEDT.

3.2.3 PV Profile

Table 3 PV Profile Details

<table>
<tr><td>Description</td><td>PV generation as a power output is obtained from translating irradiance and temperature data from Solcast into a power profile.

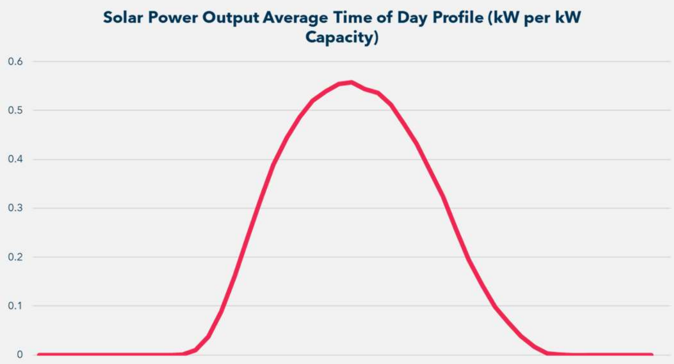


Figure 9 Time of Day Average Solar Output(kW vs Time of Day)

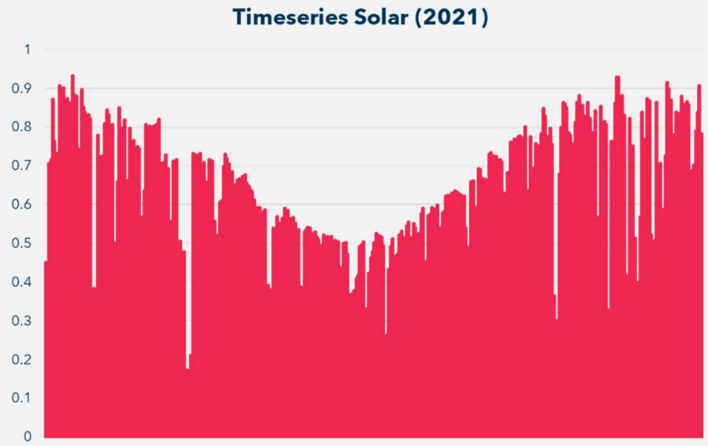


Figure 10 Timeseries Solar output (kW per kW vs Datetime)</td></tr>
<tr><td>Use</td><td>All customers with solar are allocated distinct systems (with distinct inverters).</td></tr>
<tr><td>Source</td><td>30-minute time-series Solcast data from Hoxton Park.
The data collected is from 01-01-2021 to 31-12-2021.</td></tr>
<tr><td>Data Preparation</td><td>To obtain a kW profile, the irradiance and temperature are input into the following calculation from Schneider Electric:

$$P_{solar}(t) = \sum_{i=1}^{N_{solar}} P_{solar_i}^{max} \cdot (S(t)/1000 \cdot (1 - \lambda \cdot (T_{cell}(t) - 25)) \cdot 0.95)$$</td></tr>
<tr><td>Implied Assumptions</td><td>We identified that irradiance levels were low during 2021 when data was extracted as a result of La Nina weather conditions. Therefore, after obtaining P_{solar}, the power output was scaled up by 5% within the model. This is done to align the average irradiance levels with those of the averaged previous 5 years, sourced from the BOM.</td></tr>
<tr><td>Database Details</td><td>The Solar Output is stored as the 'p_solar' in the table R_TIMESERIES_LOAD_UTC_NEW. A view also exists R_TIMESERIES_LOAD_AEDT_NEW with the timestamp converted from UTC to AEDT. Follow the link for further information.</td></tr>
</table>

3.2.4 EV Profile

Table 4 EV Profile Details

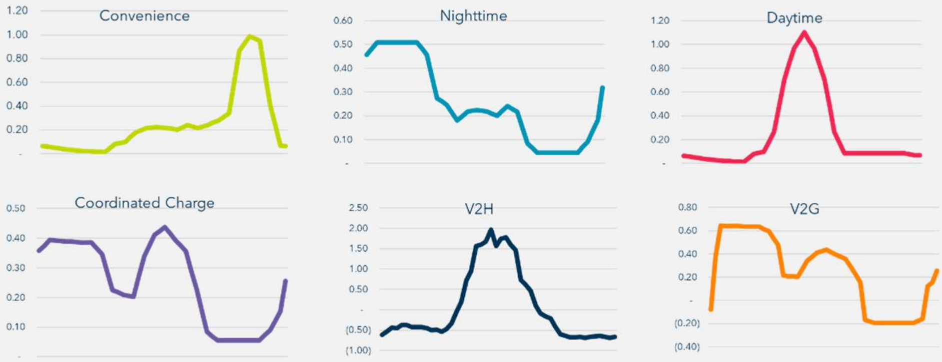
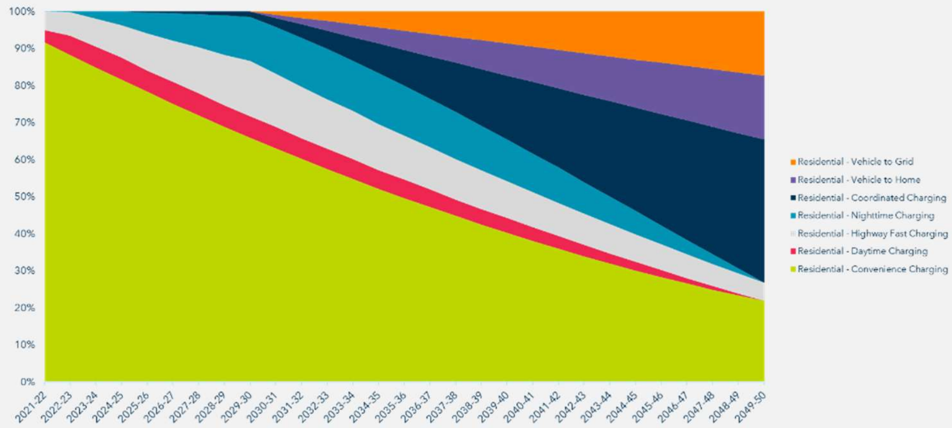
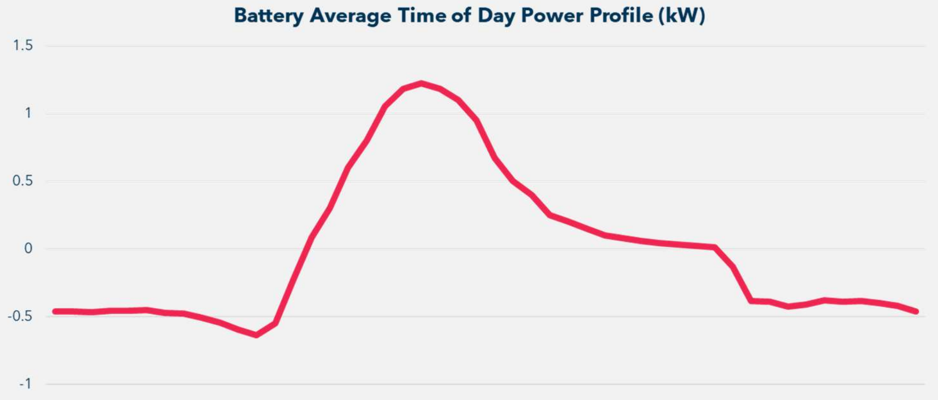
Description	Load profiles attributed to EVs are built up by 6 'charging types' to mimic the variety of charging behaviours taken up by EV owners: 1. Convenience, 2. Nighttime, 3. Daytime, 4. Coordinated, 5. Vehicle to Home (V2H), 6. Vehicle to Grid (V2G) Over time, the uptake of these mentioned charging behaviours changes. Notably, it is forecasted that the presence of convenience charging will drop by 60% in ~30 years, likely a result of advances in inverter technologies.  *Figure 11 Average of Time of Day EV Charging profile*  *Figure 12 Changing charging landscape 2021-2050*
Use	Each customer is assigned a portion of EV load where there is forecasted to be an EV.
Source	All profiles except for the Coordinated and V2G profiles are 30-minute time of day profiles sourced from AEMO. The Coordinated and V2G profiles have been designed around the tariff reforms - discharging during the night-time peak hours, charging to solar soak and overnight, when demand is generally low. Table 5 provides further commentary on the sources and processing of the EV charging profile data.
Implied Assumptions	Vehicles forecasted to be in the network area will be charging in the network area on the residential level (or otherwise will be netted off by vehicles coming into the network area).
Database Details	The EV Load Profile is stored as the 'ev_load_profile' in the table R_TIMESERIES_LOAD_UTC_NEW. A view also exists R_TIMESERIES_LOAD_AEDT_NEW with the timestamp converted from UTC to AEDT.

Table 5 Sources utilised for each EV Charging Profile

Profile	Source	Notes
Convenience	AEMO	Profiles are aligned to AEMO, however, it should be noted that a peer review was carried out examining curves from Evenergy and University of Melbourne as the convenience curve is the most influential charging profile out of the 6 used in the analysis.
Night-time	AEMO	
Daytime	AEMO	Across all profiles, we used the medium residential curves (as opposed to the small or large profiles) as the central/average position for the scenarios.
Coordinated	EE Made	Assumption made was that if the smart charger was co-ordinated by EE it would be a combination of solar soaking and night time load shifting. Ratio of the curves was set to bias night-time due to expected availability of EV at residential properties in the day being lower.
V2H	AEMO	
V2G	EE Made	Assumption is that a network-controlled charging profile also known as co-ordinated charging is a good base line for V2G. The only difference is that the network can further benefit by exporting the load during the evening peak to reduce demand on the network. In this way, the profile was modified to export 0.25kW throughout the peak window, then recover the 0.25kW throughout the overnight window.

3.2.5 Battery Profile

Table 6 Battery Profile Details

Description	Customer battery profiles demonstrate the storage of energy from what is assumed to be solar power and discharging of energy during 'peak' loading windows.  *Figure 13 Average of Time of Day Battery load profile (kW vs Time of Day)*
Use	Each customer is assigned a proportion of battery load where there is forecasted to be a battery.
Source	AEMO Summer & Winter Battery Profile, scaled to a 3.8kW inverter system with front loading adjustment to match AEMO ISP 2021 PDF figure 16 example profile.
Data Preparation	Using AEMOs battery profile in the assumptions worksheet, the profile was shifted to match the profile in the pdf document as we believe it is more accurate to what we see on the network. EE Summer and Shoulder Battery Profile • Scale AEMO Summer Battery Profile (1) AEMO profile to a 3.8kW (2) inverter system with front loading adjustment to match AEMO ISP PDF 2021 figure 16 example profile. EE Winter Battery Profile • Scale AEMO Winter Battery Profile (3) profile to a 3.8kW inverter system with front loading adjustment to match AEMO ISP 2021 PDF figure 16 example profile. *(1)* average normalised non-aggregated battery daily charge/discharge kW per kW profile for NSW in Summer (February) *(2)* GEM average inverter output 4kW, CSIRO Battery storage performance assumptions provided a guideline Maximum output = rated capacity X 85% efficiency / 2.2 with average rated capacity being 10kWh. EE aligning with CSIRO assumption with 3.8kW. *(3)* average normalised non-aggregated July daily charge/discharge kW per kW profile for NSW in Winter (July).
Implied Assumptions	The front-loading of the battery will be consistent from 2022-2040. With the advancement of inverter technology, it would be reasonable to assume that this profile will change over time to optimise for market signals and network need.
Database Details	The Battery Load Profile is stored as the 'batt_load_profile in the table R_TIMESERIES_LOAD_UTC_NEW. A view also exists R_TIMESERIES_LOAD_AEDT_NEW with the timestamp converted from UTC to AEDT.

3.3 Network Characteristics

The topology and line characteristics of the network have been modelled using real-world data, namely, exports of Endeavour Energy's ADMS and GIS LV network model data.

Operational characteristics and transformer characteristics were obtained from the enterprise asset management systems and imported into the model.

3.3.1 What Network Characteristic data is used for the modelling?

Characteristics of EE Zone Substations (ZS) and Distribution Substations (DSUBs) and LV Feeders are brought into the model, specifically:

- Zone Substation
  - Source voltage profile
  - ZS transformer voltage rating
- Distribution Substations
  - Winding impedance (r1, x1, r0, x0)
  - Source impedance (r1, x1, r0, x0)
  - KVA rating
  - Transformer winding voltage rating
  - Current tap settings
  - Tap range
- LV Feeders
  - 3-phase main feeder lengths
  - 3-phase main feeder impedance (r1, x1, r0, x0)
  - Service feeder lengths
  - Service feeder impedance
  - NMI connected to LV Feeder
  - PV assigned to each NMI

Each NMI is mapped to the associated Customer Connection Point (CCP), then LV feeder, which is mapped to the DSUB and subsequently, Zone Sub.

3.3.2 Implied Assumption(s)

Where data is missing, several assumptions are inferred from existing data. In the case of KVA ratings of DSUBS, a 'calculated' value is used as a proxy, inferred from customer counts. For other missing values, 'standard' or average values are used.

3.4 Value of Distributed Energy Resources & The Customer Export Curtailment Value

3.4.1 How is CECV used in the Hosting Capacity Analysis?

The Customer Export Curtailment Values (CECVs) are $/MWh values. CECVs are treated as an input to the model. CECVs are multiplied against the time-series curtailment alleviation profile (kWh) to obtain a quantified value for customer export curtailment in $ as shown in Figure 14.

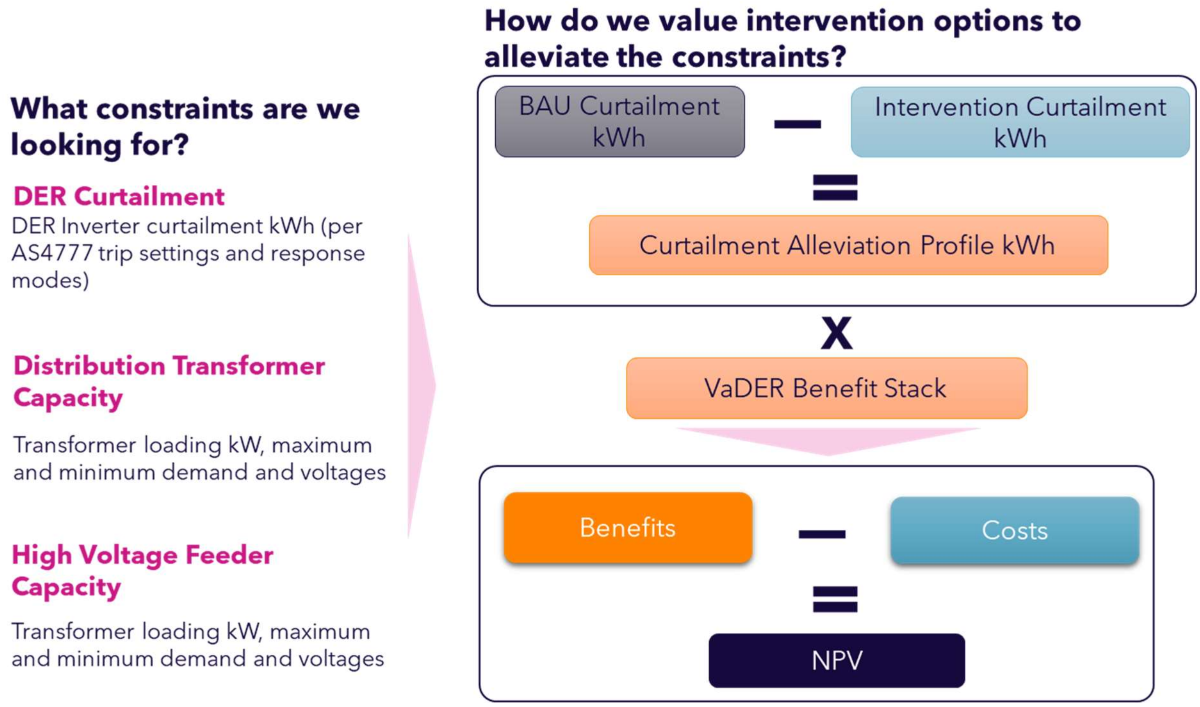


Figure 14 Use of CECV/VaDER Benefit Stack as a multiplier to the curtailment Alleviation Profile

4. Simulation Tool: DER Scenario Builder

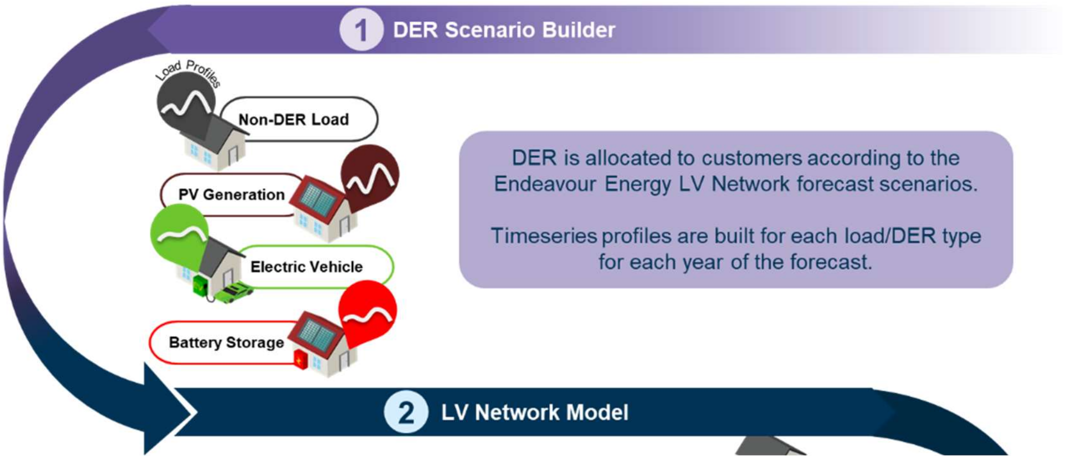


Figure 15 DER Scenario Builder

Endeavour is modelling a selection of AEMO's ISP scenarios, a central case (Step Change) along with two bookend cases (Progressive Change and Hydrogen Superpower). With each scenario, there are varying amounts of DER forecasted on the Endeavour Energy Network.

In this way, the DER Scenario Builder allocates PV systems, batteries and EVs to customers on the network so that the model aligns with the selected AEMO ISP Scenario. Within each year of the model, new DER is allocated accordingly.

4.1 PV Allocation

PV inverters are modelled explicitly in the system, so it is important to select the placement of these systems appropriately.

Existing PV customer locations are modelled accurately in the developed LV feeder model according to existing DER register data.

If the forecasted additional PV systems are assigned to the customers located at the far end of the feeder or closer to the distribution transformer this would result in extreme network conditions. It is therefore necessary to assign the new PV systems forecasted each year to non-solar customers in a way that represents average network conditions. As such, we developed an algorithm that distributes the new PV systems evenly among the non-solar customers along each LV feeder.

4.2 Battery and Electric Vehicle Allocation

Unlike PV inverters, battery storage systems and electric vehicles are not modelled explicitly in the software. For these DER types, the forecasted load profiles for each are combined with the underlying load profiles obtained from smart meters to create a new net profile that is given to all customers (as discussed in section 3.2.4 and 3.2.5. The magnitude of the DER load that is added to the baseline is proportionate to the uptake forecast for each specific LV feeder.

Once these scenarios have been developed, they can be simulated in the network model, producing a load flow of these inputs.

5. Simulation Tool: LV Network Model

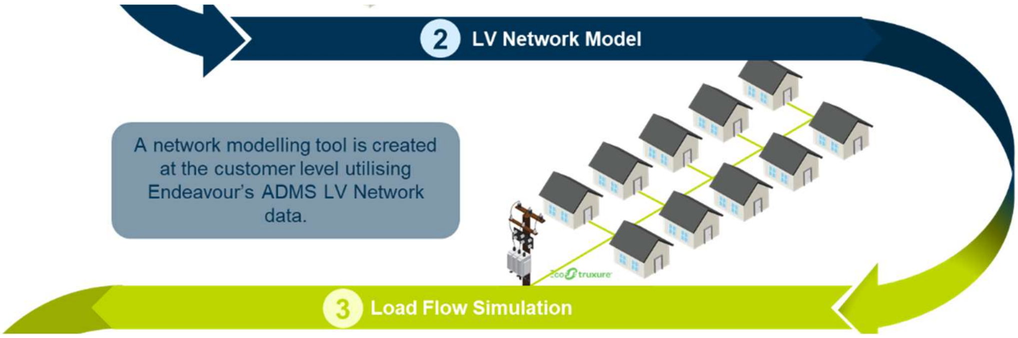


Figure 16 LV Network Model Summary

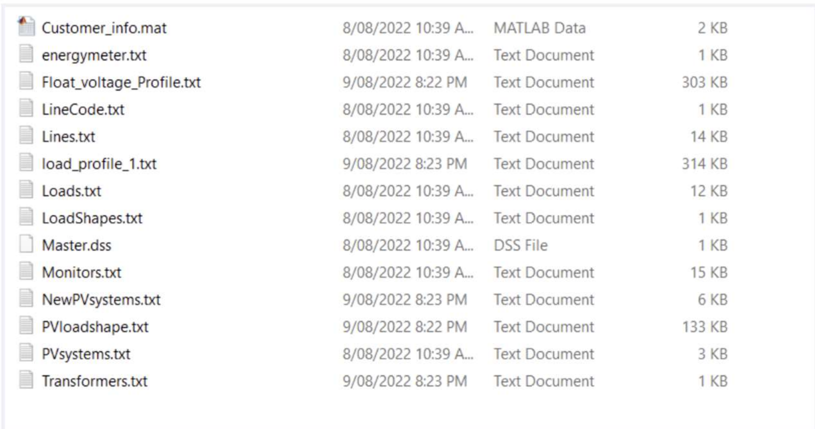
Due to the size and complexity of the modelling, **only downstream network from the distribution transformer is explicitly modelled** in the load flow analysis, using real-world data as outlined in section 3.3. The exact HV network was not included in the load flow, rather an approximation of network characteristics was used to account for upstream impacts.

MATLAB is used to build the network model files that are required for the OpenDSS software.

5.1 How is the network being modelled in OpenDSS?

We have provided OpenDSS with 3 major file 'types' in order to compile the network model. Each DSUB in the network has its own set of the files shown in Figure 17.

1. **Network model files** - those that characterise the network (Transformers, Lines, Loads, DER)
2. **Load/generation profiles** - to create a time-series profile for simulations
3. **Meter/Monitor files** – determine the placement of voltage/current/power meters on the network model and capture the outputs of the load flow.



Customer_info.mat	8/08/2022 10:39 A...	MATLAB Data	2 KB
energymeter.txt	8/08/2022 10:39 A...	Text Document	1 KB
Float_voltage_Profile.txt	9/08/2022 8:22 PM	Text Document	303 KB
LineCode.txt	8/08/2022 10:39 A...	Text Document	1 KB
Lines.txt	8/08/2022 10:39 A...	Text Document	14 KB
load_profile_1.txt	9/08/2022 8:23 PM	Text Document	314 KB
Loads.txt	8/08/2022 10:39 A...	Text Document	12 KB
LoadShapes.txt	8/08/2022 10:39 A...	Text Document	1 KB
Master.dss	8/08/2022 10:39 A...	DSS File	1 KB
Monitors.txt	8/08/2022 10:39 A...	Text Document	15 KB
NewPVsystems.txt	9/08/2022 8:23 PM	Text Document	6 KB
PVloadshape.txt	9/08/2022 8:22 PM	Text Document	133 KB
PVsystems.txt	8/08/2022 10:39 A...	Text Document	3 KB
Transformers.txt	9/08/2022 8:23 PM	Text Document	1 KB

Figure 17 OpenDSS Files

The following sections will detail the way in which the distribution transformers, LV feeder mains and service conductors, loads and PV systems and inverters are modelled within the software for the purpose of this HCM.

5.1.1 Modelling Distribution Transformers (DSUBs) in OpenDSS

OpenDSS uses the 'transformer.txt' file to model transformers.

Transformers.txt - Notepad

File Edit Format View Help

```
New Transformer.TR1 Buses=[SourceBus 1] Conns=[Delta Wye] kVs=[1.127500e+01 0.433] kVAs=[315 315] %R=0.8564 XHL=3.8262 sub=y
```

Figure 18 Transformers.txt snippet

Transformer.txt defines the voltage source and characteristics of the distribution transformer including its configuration, primary and secondary voltages, KVA rating and source impedances.

The transformer characteristics may change because of tap optimisation efforts, altering the primary (HV) side of the DSUB.

5.1.2 Modelling LV Feeder Mains and Service Conductor in OpenDSS

The LV feeders that are modelled by the simulation tool are radial in nature and a simplified illustration of the developed LV feeder model is given below.

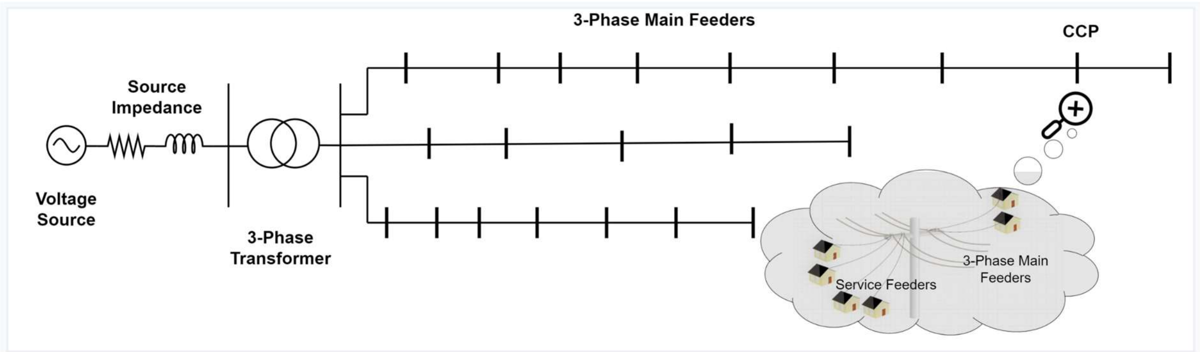


Figure 19 Radial Feeder Model

Real data is used for the distances and the impedances of the LV feeders from the DSUB to the customer. However, LV feeder spurs are not included in the developed model due to the unavailability of data on the location of the LV feeder spurs. All the main LV feeders are 3-phase feeders and all the service feeders that connects the customers to the customer connection point (CCP) are single phase. The location of customers in the LV feeders are modelled based on their respective main feeder lengths and service feeder lengths. MV side of the network is modelled as a voltage source that operates according to a voltage profile with a fixed source impedance. The exact phase that a customer is connected to in the LV feeder is unknown. Therefore, for unbalanced scenarios, an unbalanced ratio is applied to customers (in the case of the model, 50:30:20) and customers are assigned a phase accordingly. For balanced scenarios, all the customers in the LV feeder are distributed evenly among the three phases (specifically a ratio of 37:33:30). The customer loads are assumed to be of unity power factor.

OpenDSS uses the following files to model LV Feeder Conductors:

- Lines.txt
- LineCode.txt

Lines.txt defines the buses on each LV feeder and length, assigning each customer to a bus with a service feeder of a specific length. The characteristics of these lines are dictated in the file LineCode.txt , shown in Figure 21.

LineCode.txt defines R1, X1, R0, X0, C1 and C0 for each LV feeder and LV feeder service.

LineCode.txt - Notepad

File Edit Format View Help

```
New LineCode.LVFEED-63949945 nphases=3 R1=0.00018091 X1=0.00008924 R0=0.00018091 X0=0.00008924 C1=0 C0=0 Units=m
New LineCode.LVFEED-63949945_Service nphases=1 R1=0.00010692 X1=0.00008884 R0=0.00010692 X0=0.00008884 C1=0 C0=0 Units=m
New LineCode.LVFEED-63949946 nphases=3 R1=0.00025700 X1=0.00008400 R0=0.00025700 X0=0.00008400 C1=0 C0=0 Units=m
New LineCode.LVFEED-63949946_Service nphases=1 R1=0.00020444 X1=0.00023117 R0=0.00020444 X0=0.00023117 C1=0 C0=0 Units=m
```

Figure 20 LineCode.txt snippet

Lines.txt - Notepad

File Edit Format View Help

```
New Line.LINE2 Bus1=1 Bus2=2 phases=3 Linecode=LVFEED-63923426 Length=33.3100 Units=m
New Line.LINE3 Bus1=2 Bus2=3 phases=3 Linecode=LVFEED-63923426 Length=18.5400 Units=m
New Line.LINE4 Bus1=3 Bus2=4 phases=3 Linecode=LVFEED-63923426 Length=20.5600 Units=m
New Line.LINE5 Bus1=4 Bus2=5 phases=3 Linecode=LVFEED-63923426 Length=18.6400 Units=m
New Line.LINE6 Bus1=5 Bus2=6 phases=3 Linecode=LVFEED-63923426 Length=0.5900 Units=m
New Line.LINE7 Bus1=6 Bus2=7 phases=3 Linecode=LVFEED-63923426 Length=36.7500 Units=m
New Line.LINE8 Bus1=7 Bus2=8 phases=3 Linecode=LVFEED-63923426 Length=45.0000 Units=m
New Line.LINE9 Bus1=8 Bus2=9 phases=3 Linecode=LVFEED-63923426 Length=43.0300 Units=m
New Line.LINE10 Bus1=9 Bus2=10 phases=3 Linecode=LVFEED-63923426 Length=15.2000 Units=m
New Line.LINE11 Bus1=10 Bus2=11 phases=3 Linecode=LVFEED-63923426 Length=37.6000 Units=m
New Line.LINE12 Bus1=11 Bus2=12 phases=3 Linecode=LVFEED-63923426 Length=45.0000 Units=m
New Line.LINE13 Bus1=12 Bus2=13 phases=3 Linecode=LVFEED-63923426 Length=26.6300 Units=m
New Line.LINE14 Bus1=13 Bus2=14 phases=3 Linecode=LVFEED-63923426 Length=15.7700 Units=m
New Line.LINE15 Bus1=1 Bus2=15 phases=3 Linecode=LVFEED-63923427 Length=36.9500 Units=m
New Line.LINE16 Bus1=15 Bus2=16 phases=3 Linecode=LVFEED-63923427 Length=33.7100 Units=m
New Line.LINE17 Bus1=16 Bus2=17 phases=3 Linecode=LVFEED-63923427 Length=3.0000 Units=m
New Line.LINE18 Bus1=17 Bus2=18 phases=3 Linecode=LVFEED-63923427 Length=27.5000 Units=m
New Line.LINE19 Bus1=18 Bus2=19 phases=3 Linecode=LVFEED-63923427 Length=12.3300 Units=m
New Line.LINE20 Bus1=19 Bus2=20 phases=3 Linecode=LVFEED-63923427 Length=23.0700 Units=m
New Line.LINE21 Bus1=20 Bus2=21 phases=3 Linecode=LVFEED-63923427 Length=9.2500 Units=m
New Line.LINE22 Bus1=21 Bus2=22 phases=3 Linecode=LVFEED-63923427 Length=4.2800 Units=m
New Line.LINE23 Bus1=22 Bus2=23 phases=3 Linecode=LVFEED-63923427 Length=19.5700 Units=m
New Line.LINE24 Bus1=23 Bus2=24 phases=3 Linecode=LVFEED-63923427 Length=13.3500 Units=m
New Line.LINE25 Bus1=24 Bus2=25 phases=3 Linecode=LVFEED-63923427 Length=35.2000 Units=m
New Line.LINE26 Bus1=25 Bus2=26 phases=3 Linecode=LVFEED-63923427 Length=40.7000 Units=m
New Line.LINE2_2_4310165199 Bus1=2.2 Bus2=2_2_4310165199 phases=1 Linecode=LVFEED-63923426_Service Length=27.7400 Units=m
New Line.LINE2_3_4310165215 Bus1=2.3 Bus2=2_3_4310165215 phases=1 Linecode=LVFEED-63923426_Service Length=27.7400 Units=m
New Line.LINE2_1_4310165216 Bus1=2.1 Bus2=2_1_4310165216 phases=1 Linecode=LVFEED-63923426_Service Length=11.8000 Units=m
New Line.LINE2_2_4311401996 Bus1=2.2 Bus2=2_2_4311401996 phases=1 Linecode=LVFEED-63923426_Service Length=20.1400 Units=m
New Line.LINE3_3_4310157871 Bus1=3.3 Bus2=3_3_4310157871 phases=1 Linecode=LVFEED-63923426_Service Length=24.1000 Units=m
```

Figure 21 Lines.txt snippet

Calculating per unit impedance and reactance for feeder mains and service mains

R1, X1, R0, X0, C1, C0 Mains values are calculated *per feeder*. To achieve a uniform per unit impedance, the algorithm searches for the customer furthest away from the DSUB, records its impedance values (R, R0, X, X0) and divides them by the length of the mains feeder. To demonstrate this method, an example below using 'LVFEED-63932246' is shown.

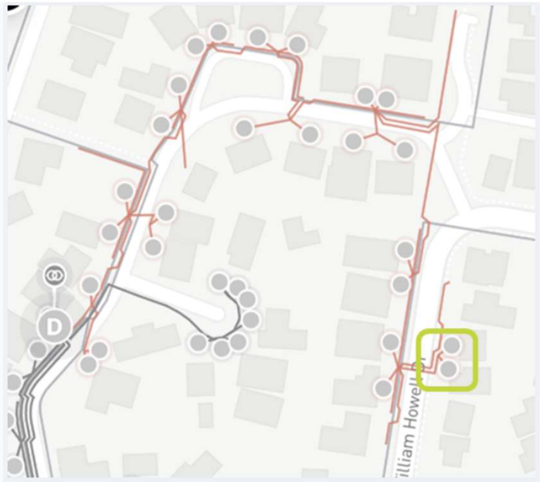


Figure 22 LVFEED-63932246, highlighted customers at the end of the line

Step 1: Identify distance of customers at the end of the feeder.

> *Here, 4310358288 and 4310358268, are 433.56m away from DSUB 12589.*

Step 2: Record impedance values and divide by mains length to obtain per unit measurements.

NMI	Length	R	R0	X	X0	R pu	R0 pu	X pu	X0 pu
4310358268	433.56	8.85E-02	8.85E-02	2.87E-02	2.87E-02	2.04E-04	2.04E-04	6.62E-05	6.62E-05
4310358288	433.56	8.85E-02	8.85E-02	2.87E-02	2.87E-02	2.04E-04	2.04E-04	6.62E-05	6.62E-05

Figure 23 Per Unit Calculation of Impedance and Reactance

For service conductors, values are calculated *per LV feeder*. To achieve a uniform per unit impedance, the average value is taken from the database per LV Feeder.

5.1.3 Modelling Customer Loads in OpenDSS

Customer connections are accounted for as loads in the HCM. Loads are assigned to buses and they can be given a static load, or be overridden and dictated by time-series 'load profiles'.

We have assigned time-series load profiles to the model as described in Section 0.

Loads.txt - Notepad

File Edit Format View Help

```
New Load.LOAD2_2_4310165199 Phases=1 Bus1=2_2_4310165199 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD2_3_4310165215 Phases=1 Bus1=2_3_4310165215 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD2_1_4310165216 Phases=1 Bus1=2_1_4310165216 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD2_2_4311401996 Phases=1 Bus1=2_2_4311401996 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD3_3_4310157871 Phases=1 Bus1=3_3_4310157871 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD4_1_4310165222 Phases=1 Bus1=4_1_4310165222 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD5_2_4310157872 Phases=1 Bus1=5_2_4310157872 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD5_3_4310157873 Phases=1 Bus1=5_3_4310157873 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD5_1_4310157897 Phases=1 Bus1=5_1_4310157897 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD5_2_4310157898 Phases=1 Bus1=5_2_4310157898 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD6_3_4310165217 Phases=1 Bus1=6_3_4310165217 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
New Load.LOAD6_1_4310165218 Phases=1 Bus1=6_1_4310165218 kV=0.23 kW=1.8966 PF=1 Model=1 Vminpu=0.8 Vmaxpu=1.2 yearly=Shape_1
```

Figure 24 Loads.txt snippet

LoadShapes.txt - Notepad

File Edit Format View Help

```
New Loadshape.Shape_1 npts=17198 minterval=30 mult=(file=Load_profile_1.txt) useactual=true
```

load_profile_1.txt - Notepad

File Edit Format View Help

```
0.869973345661399
0.837046606370361
0.724360799628366
0.572727239610503
0.476557940448791
0.448970426231781
0.408265944456416
0.401610667346016
0.373251883253346
0.362228581942731
0.342929979075468
0.325419591738321
0.328469428201513
0.387064761293971
```

Figure 25 LoadShapes.txt and load_profile_1.txt snippet

5.1.4 Modelling Solar PV Systems and Inverters in OpenDSS

PV Systems and New PV Systems assign a distinct solar system and inverter to an individual customer. Inverter curves are also defined in the OpenDSS files and the operating modes of the inverter.

Existing systems and new systems are modelled differently. The chart below demonstrates the key distinctions between the two.

Characteristic / PV System Modelled	PV Systems Installed prior to 2022	PV Systems Installed Post 2022
Size	4.9 kW *(average size of systems installed prior to 2022)*	7 kW *(average size of systems installed in 2022)*
Inverter Settings	AS/NZS 4777.2.2015 Volt-Watt Enabled	AS/NZS 4777.2.2020 Volt-VAr, Volt-Watt Enabled

Figure 26 Distinctions between modelling existing PV systems vs new PV systems

The PV panels are modelled to be oversized by 20% of their respective inverter rating. To reduce the time taken for the simulation by the COM interface, inverter control functions available within the OpenDSS environment are used in this study.

Inverter Model

As shown in Figure 26, existing PV-customer inverters are modelled only with the Volt-Watt control function using the settings specified by the standards AS 4777.2:2015.

Inverters of the forecasted PV customers are modelled to be operated in a combined Volt-Var and Volt-Watt mode following the standards AS4777.2:2020. The Volt-Var function is set to operate in reactive power priority mode, which would prioritise the output of reactive power to regulate the voltage when the active power output of the inverter approaches closer to the inverter rating. The reactive power available for the inverter to regulate the voltage is calculated according to the below equation.

$$kVar = \sqrt{(Inverter\ rating)^2 - (kWOutput)^2}$$

Export Limits

According to the AS 4777.2:2020 standards, the inverter should trip or disconnect from the grid if the average voltage for a time period of 10-minutes exceeds 258V. Due to lack of high-resolution data, the inverters are set to be tripped when the local voltage reaches beyond 258V for every 30-minute time step. This introduces a slight error into the calculated customer curtailment values and voltages.

OpenDSS uses the following files to model PV Systems & Inverters:

- PVSystems.txt
- NewPVSystems.txt

PVsystems - Notepad

File Edit Format View Help

```
New loadshape.PV_Loadshape npts=17198 minterval=30 mult=(file=PVloadshape.txt) useactual=true
New pvsystem.PV_load3_1_4310080499 bus1=3_1_4310080499 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load4_2_4310080496 bus1=4_2_4310080496 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load4_1_4310080538 bus1=4_1_4310080538 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load4_1_4310080550 bus1=4_1_4310080550 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load5_1_4310080532 bus1=5_1_4310080532 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load6_3_4310112495 bus1=6_3_4310112495 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load7_2_4310080492 bus1=7_2_4310080492 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load7_3_4310080493 bus1=7_3_4310080493 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load7_3_4310080542 bus1=7_3_4310080542 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
New pvsystem.PV_load8_2_4310112501 bus1=8_2_4310112501 irradiance=1 phases=1 kv=0.23 pmpp=5.88 kva=4.90 yearly=PV_Loadshape
```

NewPVsystems - Notepad

File Edit Format View Help

```
New XYCurve.vwc_curve npts=4 Yarray=(1 1 1 0.678 0) XArray=(0.9 0.956 1.087 1.122 1.122)
New XYCurve.myvwc_curve npts=4 Yarray=(1 1 1 0.413 0) XArray=(0.9 0.956 1.1 1.122 1.122)
New XYCurve.myvvc_curve npts=6 Yarray=(0 0 -0.44 0) XArray=(0.956 1.043 1.122 1.122)
New pvsystem.PV_load3_2_4310080500 bus1=3_2_4310080500  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load3_3_4310080536 bus1=3_3_4310080536  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load3_2_4310939102 bus1=3_2_4310939102  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load3_3_4310939103 bus1=3_3_4310939103  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load4_3_4310080510 bus1=4_3_4310080510  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load5_2_4310080547 bus1=5_2_4310080547  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load5_3_4310080552 bus1=5_3_4310080552  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load5_1_4311287722 bus1=5_1_4311287722  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load7_2_4310080537 bus1=7_2_4310080537  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load8_3_4310112496 bus1=8_3_4310112496  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load10_3_4310112492 bus1=10_3_4310112492  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load11_1_4310112489 bus1=11_1_4310112489  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load11_3_4310112506 bus1=11_3_4310112506  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load12_3_4310080504 bus1=12_3_4310080504  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load16_2_4310085962 bus1=16_2_4310085962  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load17_1_4310085978 bus1=17_1_4310085978  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load19_2_4310085956 bus1=19_2_4310085956  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load21_1_4310085967 bus1=21_1_4310085967  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load21_3_4310085975 bus1=21_3_4310085975  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load24_3_4310085973 bus1=24_3_4310085973  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New pvsystem.PV_load25_1_4311146022 bus1=25_1_4311146022  irradiance=1 phases=1 kv=0.23 pmpp=8.40 kva=7.00 %PminNoVars=20 VarFollowInverter=True yearly=PV_Loadshape
New InvControl.PVcontrol_1  DERList=[pvsystem.PV_load3_1_4310080499 pvsystem.PV_load4_2_4310080496 pvsystem.PV_load4_1_4310080538 pvsystem.PV_load4_1_4310080550 pvsystem.PV_load5_1_4310080
New InvControl.PVcontrol_2  DERList=[pvsystem.PV_load3_2_4310080500 pvsystem.PV_load3_3_4310080536 pvsystem.PV_load3_2_4310939102 pvsystem.PV_load3_3_4310939103 pvsystem.PV_load4_3_4310080
Set maxcontroliter=200
```

Figure 27 PVSystems.txt and NewPVSystems.txt snippet

Each year, the NewPVSystems.txt file is refreshed to reflect the added PV systems.

Each intervention option modelled requires an initial ‘unconstrained’ run (without any inverter control) and then with the inverter control on to measure curtailment.

6. Simulation Tool: Load Flow Simulation

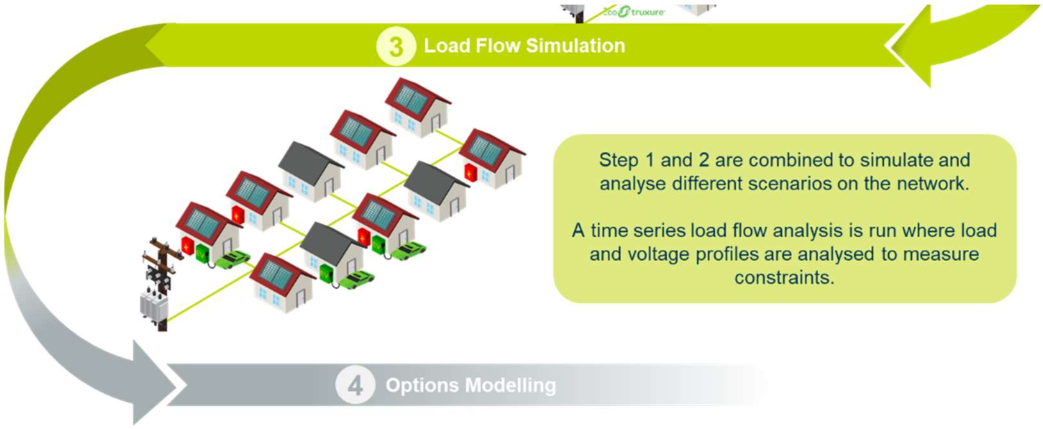


Figure 28 Load Flow Simulation Summary

With stage 1 and 2 complete: DER Scenario Builder and the LV Network model, the DER is allocated to the customers and the network is built. Now OpenDSS can complete load flow simulations for each customer. Results from each run are collected into the database.

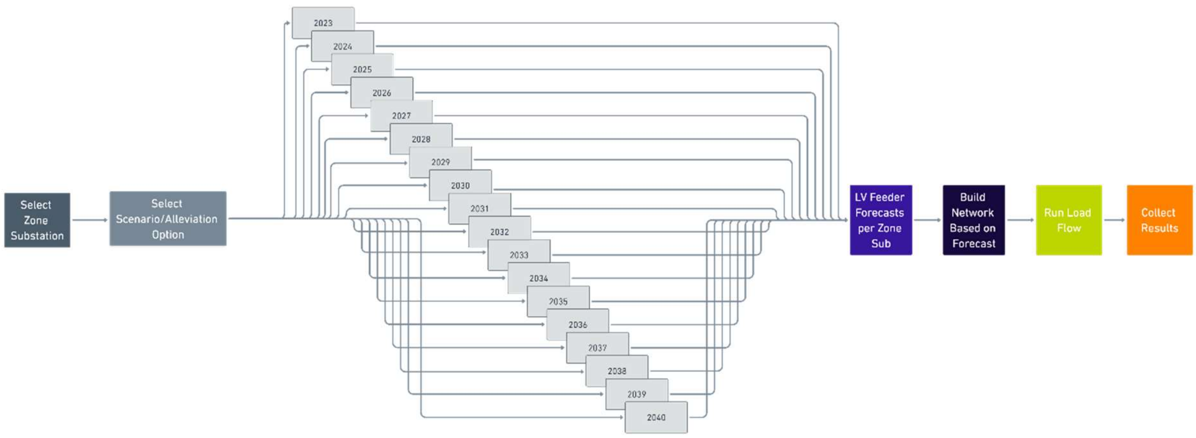


Figure 29 Visual representation of all the load flow simulations run for 1 Zone Sub

7. Simulation Tool: Alleviation Options Modelling

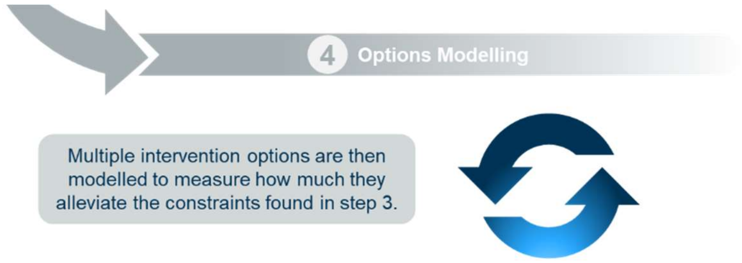


Figure 30 Options Modelling Summary

In response to the measured constraints, we have explored 7 intervention steps that build upon each other to alleviate the constraints resulting from increase DER integration in the simulations.

For these interventions to be accurately modelled, we built additional functionality into the simulation tool to modify:

1. load profiles to simulate tariff reforms, and
2. the scripts that build the OpenDSS model, changing parameters of equipment configurations, voltage setpoints and customer connection point phasing.

This additional functionality has created a robust simulation tool that can measure the improvements in curtailment as each intervention is added to the scenarios.

7.1 Modelled Scenarios

1. Base Case – Network remains as is, BAU
2. Tariff Reform - Modelled through altering the load profile
3. Phase Balancing - Modelled by changing phase allocation of customers
4. Distribution Tap Optimisation - Modelled by changing network characteristics
5. Dynamic Voltage Management (DVMS) - Modelled through changing float voltages
6. Controlled Load Hot Water Solar Soaking- Modelled through altering the load profile
7. Network Investment - Modelled through a financial analysis, post modelling
8. Dynamic Operating Envelopes – Value derived from a pseudo model, estimating the value lost to export limits.

Each intervention scenario builds upon the last as shown in Figure 31.

Interventions\ Scenario	Time of Use Load Profile	Balanced Phases?	Optimise Taps?	DVMS?	Controlled Loads?
Base Case	✗	✗	✗	✗	✗
Tariff Reform	✓	✗	✗	✗	✗
Phase Balancing	✓	✓	✗	✗	✗
Tap Optimisation	✓	✓	✓	✗	✗
DVMS	✓	✓	✓	✓	✗
Controlled Loads	✓	✓	✓	✓	✓

Figure 31 Modelled Scenarios and Intervention Actions Activated

7.1.1 Tariff Reform

The Tariff Reform Scenario aims to reflect the impacts of new tariffs on hosting capacity.

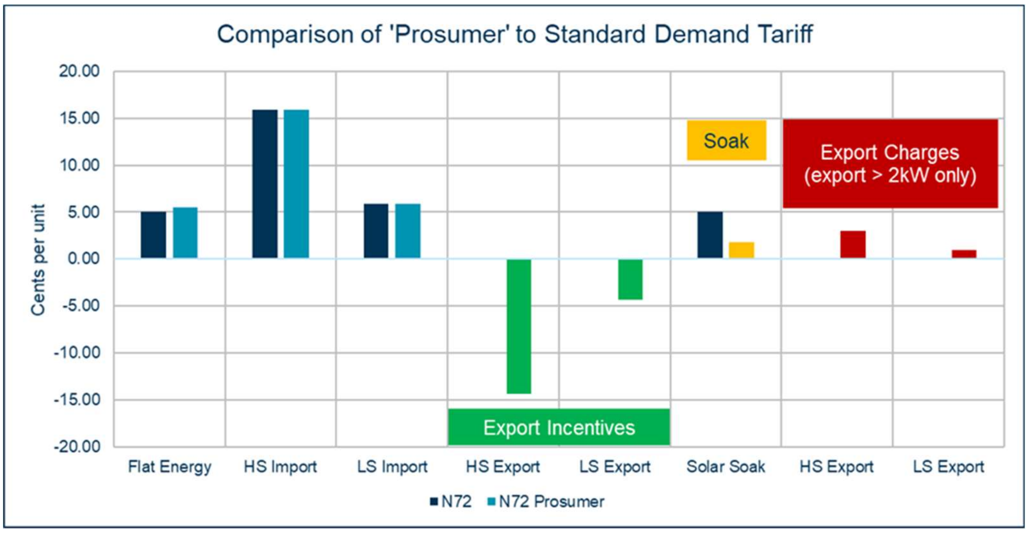


Figure 32 Prosumer Tariff Structure vs Demand Tariff

In this way, the network is modelled with the following parameters:

Network Characteristics:

- Typical float voltage at Zone
- Recorded DSUB Tap Positions
- Typical LV Phase unbalance

Load Profiles:

- The typical non-der customer load profile is used but modified to represent the shifting of load into different times of the day as a result of new tariffs. Several assumptions have been made regarding the uptake of these new tariffs and the impact they will have on customer behaviour as discussed below.

Tariff Uptake

Tariff uptake rate (per year) represents the possible net shift in behaviour by customers and is therefore dependant on Zone and Scenario. All factors only consider the non-DER load profile as tariff impacts for EV and Battery curves are built into the model, which equates to ~17.2kWh of daily load.

Moreover, the factors can only be applied to customers that do not have a battery system – annual penetration of customers without a battery is shown in Table 7.

Table 8 in the Appendix outlines the factors taken into consideration for tariff impact. They include:

- % penetration of smart meters - only smart meter customers will have access to TOU tariffs
- Assignment Policy - the percentage of customers where the network tariff we set is assigned to the customer.
- Retailer Pass Through - since retailers are not obligated to pass through price signals to customers resulting in no change of customer behaviour. We estimate a year-on-year increase in retailer pass through up to 60%.

- Customer’s Fraction of Shift-able load - This percentage represents the amount of load that is movable as we acknowledge that a portion of customer loads may be constant. We estimate a maximum shift-able load of 20%.
- Price response - We assume electricity is strongly price inelastic (our forecasting model uses between -0.15 and -0.07 – that is, a 10% increase in price will result in a 1.5% to 0.7% reduction in demand).

Load Shifting Profile (Time of Day)

The price signalling results in a reduced night-time peak with energy moved into the off peak and solar soaking period as illustrated on the average day profile in Figure 33 below.

The shift profile below is scaled to the daily kWh hour figure. It shows the increase of energy used in the early morning and midday and decrease of energy used in the evening peak hours. The impact of this load shifting can be seen in the underlying load profile shown in Figure 34. Also considering the battery and EV loads, the impacts of a TOU tariff can be seen in Figure 35.

Figure 33 Load shift profile kW per kWh to shift

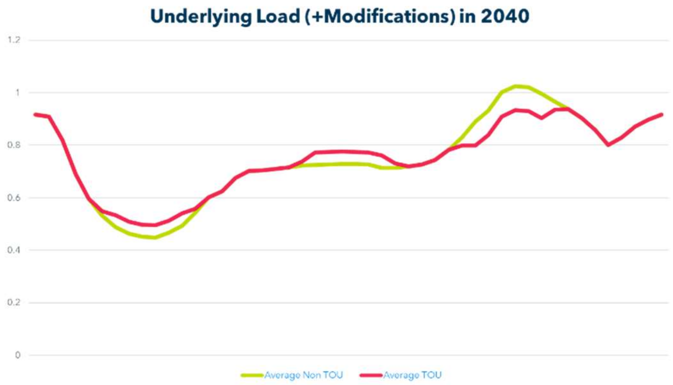


Figure 34 Non-DER (underlying) load profile with and without TOU tariff reform

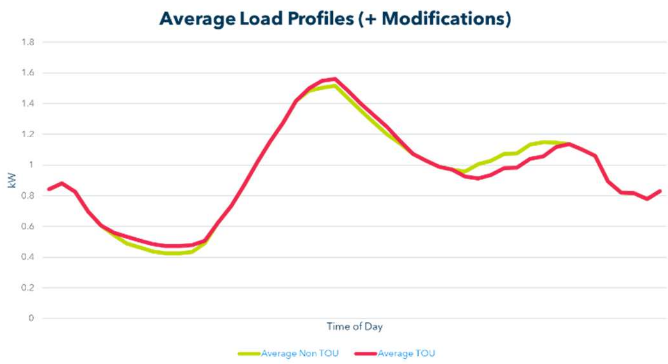


Figure 35 Adjusted average time of day load profile due to the adoption of a TOU tariff (year 2040)

7.1.2 Phase Balancing

The Phase Balancing Scenario aims to reflect the impacts of improving the phases assigned to customers.

Ideally, the connection of all customers should be spread evenly across all phases to balance the loading on the network. However, in reality, unbalance exists, typically weighted towards the conductor closest to the house. LV analytics is able to identify the level and location of unbalance on the network allowing for corrections to be made at the point of connection to another phase.

In this way, the network is modelled with the following parameters:

- **Network Characteristics:**
    - Typical float voltage at Zone
    - Recorded DSUB Tap Positions
    - Improved phase balancing by changing the ratio of assignment to 37:33:30 (compared to 50:30:20 previously)
- **Load Profiles:**
    - The typical non-der customer load profile is used with the modifications made to represent the shifting of load into different times of the day as a result of new tariffs.

Using the LV analytics platforms, we have determined that the average unbalance on LV networks is a 50%/30%/20% split across the available three phases. On the other hand, parts of the network that are considered balanced have a 37%/33%/30% split. This is measured by the observed voltage on each of the phases through the purchased smart meter data as shown in Figure 36.

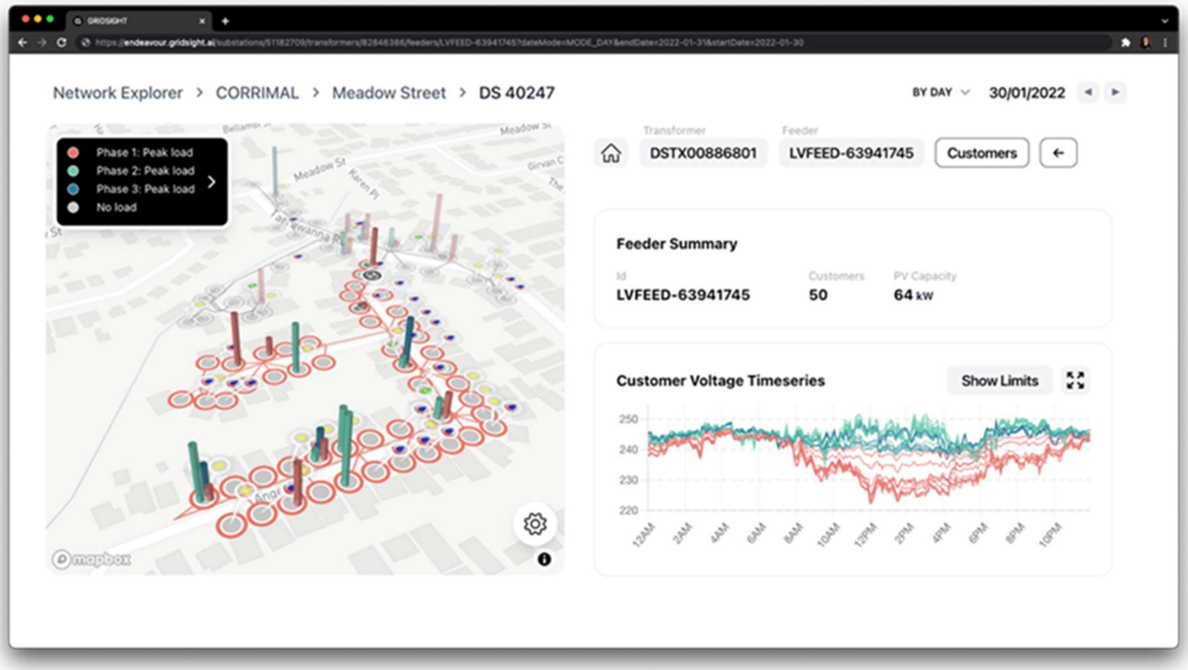


Figure 36 Gridsight platform showing voltage spread per phase

7.1.3 Distribution Tap Optimisation

The Tap Optimisation Scenario aims to reflect the impacts of the continued impacts of the Tap Optimisation Program.

In this way, the network is modelled with the following parameters:

- **Network Characteristics:**
    - Typical float voltage at Zone
    - Optimal DSUB Tap Positions
    - Improved phase balancing by changing the ratio of assignment to 37:33:30 (compared to 50:30:20 previously)
- **Load Profiles:**
    - The typical non-der customer load profile is used with the modifications made to represent the shifting of load into different times of the day as a result of new tariffs.

How is the optimal tap position determined?

The tap optimisation algorithm will first determine whether tap changing is a suitable solution. To do this, it filters out DSUBs that have a V1 and V99 that is non-compliant i.e., outside the range of 230V+10%-6% (or 216V-253V).

Each year, we have allowed for ~800 DSUBs to be tapped which aligns with the maximum number of DSUBs we have tapped a given year. The selection process for DSUBs that require a tap change is shown in Figure 37.

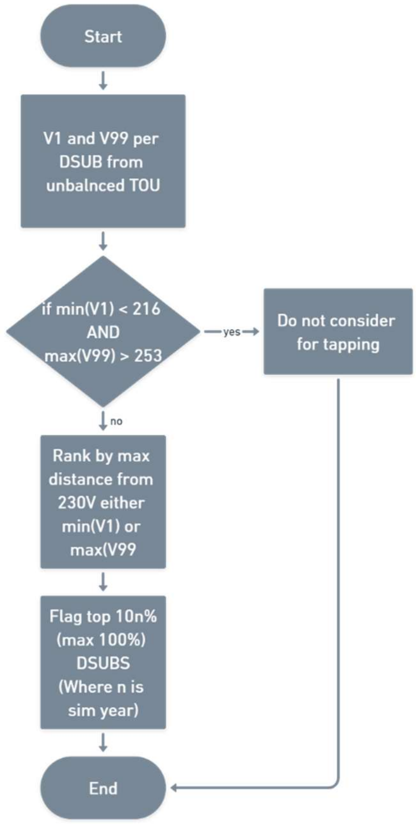


Figure 37 Select DSUBs to Tap

If the DSUB is suitable for tapping, the tap optimisation algorithm will attempt to select the number of buck or boost taps required as shown in the code snippet and flow charts below.

```
Optimize = true;

if Vmin_opt > 230.5 && Vmax_opt > 253
    OptimizeFlag = 1; % tap down twice
elseif Vmin_opt > 224.5 && Vmax_opt > 253
    OptimizeFlag = 2; % tap down once
elseif Vmin_opt < 216 && Vmax_opt >= 247.25 && Vmax_opt < 253
    OptimizeFlag = 3; % tap up once
elseif Vmin_opt <= 210.25 && Vmax_opt < 247.25
    OptimizeFlag = 4; % tap up twice
else
    OptimizeFlag = 0;
    Optimize = false;
end
```

Figure 38 Tap optimisation code snippet

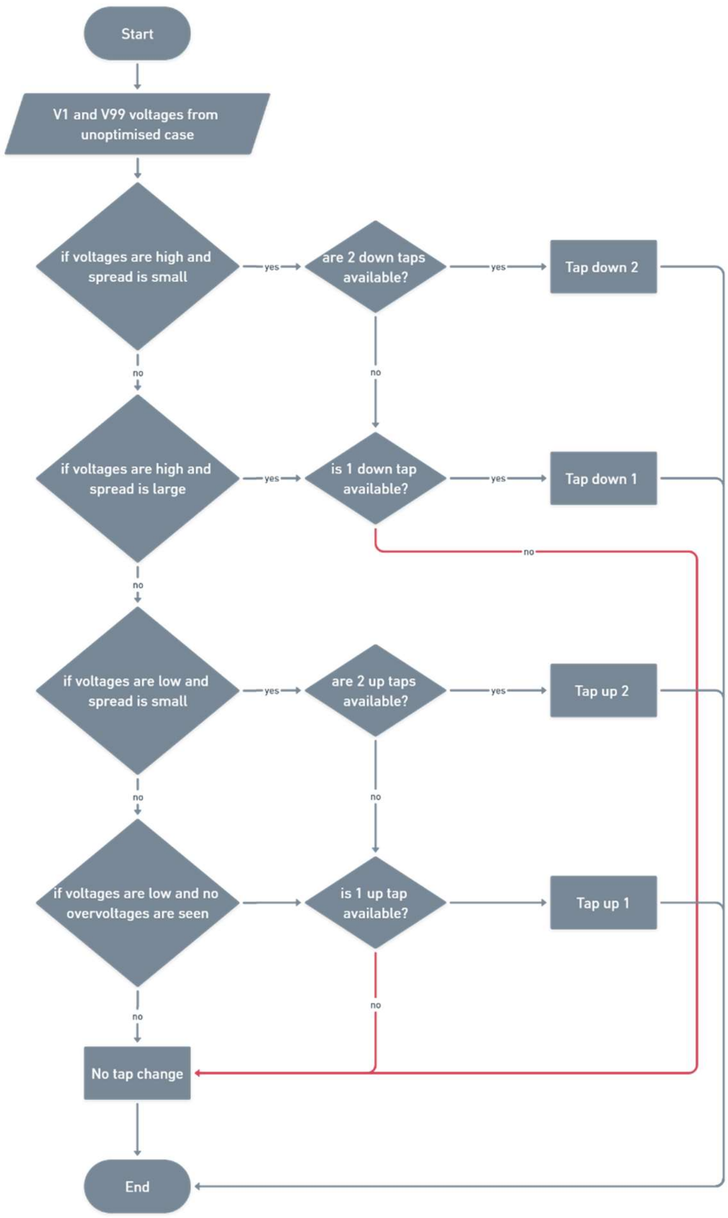


Figure 39 Tap optimisation decision flow

7.1.4 Dynamic Voltage Management System

The DVMS scenario implements an algorithm that dynamically determines a ZS voltage target (set point) to optimise the voltage levels on the network. This, in turn, will enable higher levels of hosting capacity.

In this way, the network is modelled with the following parameters:

- **Network Characteristics:**
  - Optimised, dynamically managed voltage at Zone
  - Optimal DSUB Tap Positions
  - Improved phase balancing by changing the ratio of assignment to 37:33:30 (compared to 50:30:20 previously)
- **Load Profiles:**
  - The typical non-der customer load profile is used with the modifications made to represent the shifting of load into different times of the day as a result of new tariffs. Additional modifications to the load profile are made to reflect the increase of controlled load hot water soaking

The DVMS float voltage set point is selected as shown in the below diagram.

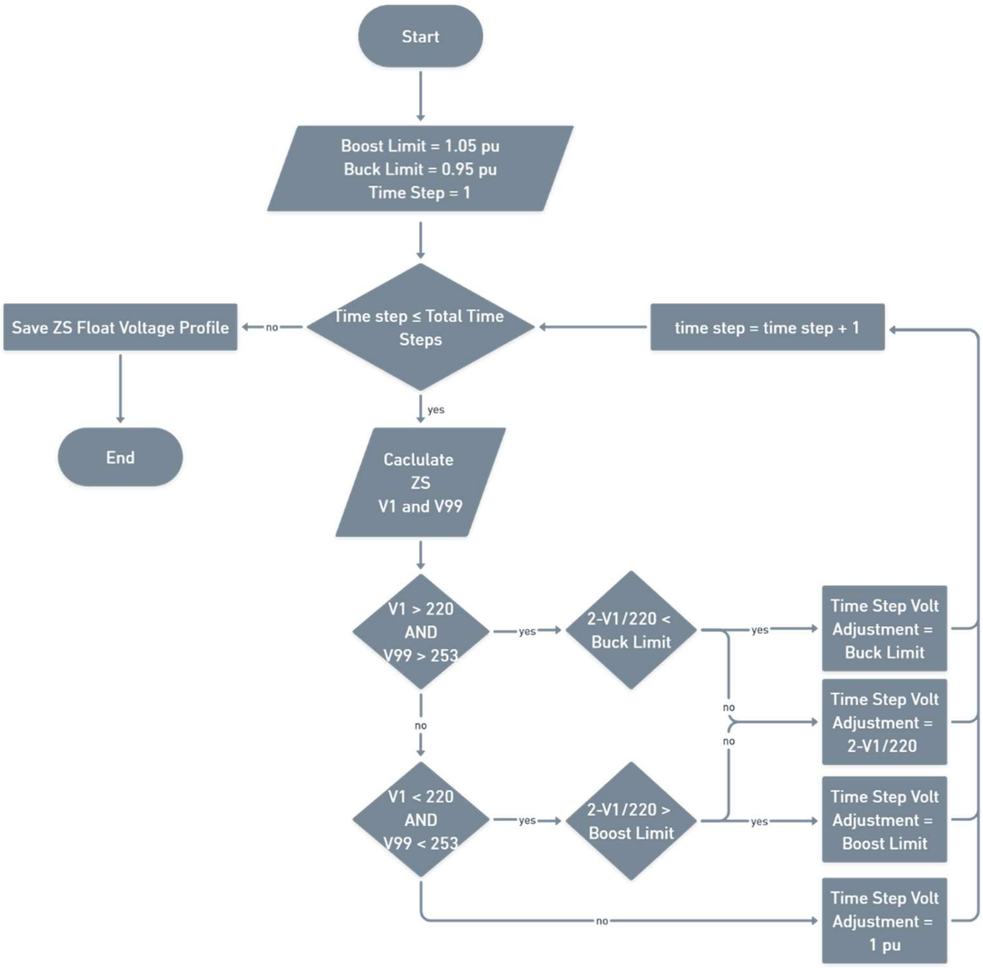


Figure 40 DVMS setpoint algorithm flow

7.1.5 Controlled Load Hot Water Solar Soaking

Our Off Peak Plus pilot project demonstrated that smart meters can be used to deliver flexible and reliable hot water solar soaking without impacting customer amenity.

The Controlled Loads Scenario aims to reflect the impacts of a larger roll-out of transitioning Off Peak Controlled Load customers onto the Off Peak Plus Controlled Loads program which focuses on the benefits of hot water solar soaking.

In this way, the network is modelled with the following parameters:

- **Network Characteristics:**
    - Optimised, dynamically managed voltage at Zone
    - Optimal DSUB Tap Positions
    - Improved phase balancing by changing the ratio of assignment to 37:33:30 (compared to 50:30:20 previously)
- **Load Profiles:**
    - The typical non-der customer load profile is used with the modifications made to represent the shifting of load into different times of the day as a result of new tariffs. Additional modifications to the load profile are made to reflect the increase of controlled load hot water soaking. The modifications are dependant on CL uptake and load shift as a result of controlled loads.

Off Peak Plus Uptake

Off Peak Plus uptake rate (per year) represents the possible net shift of customers with controlled loads onto the Off Peak Plus tariff from the traditional off peak tariff and is therefore dependant on Zone and Scenario as shown in Figure 42 below.

Figure 41 below shows a 'BAU natural churn' of this uptake vs an 'Accelerated trend' which captures a faster rate of smart meter roll-outs. The model utilises the 'Accelerated trend' scenario and shows ~261k customers (the current number of CL customers on the network) with hot water soaking capability by 2028-2029.

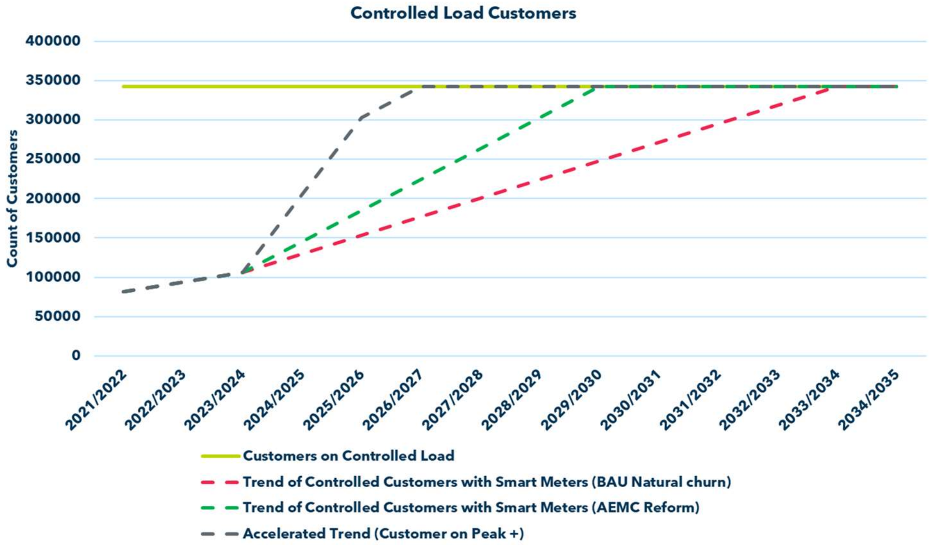


Figure 41 Network wide uptake of off peak plus

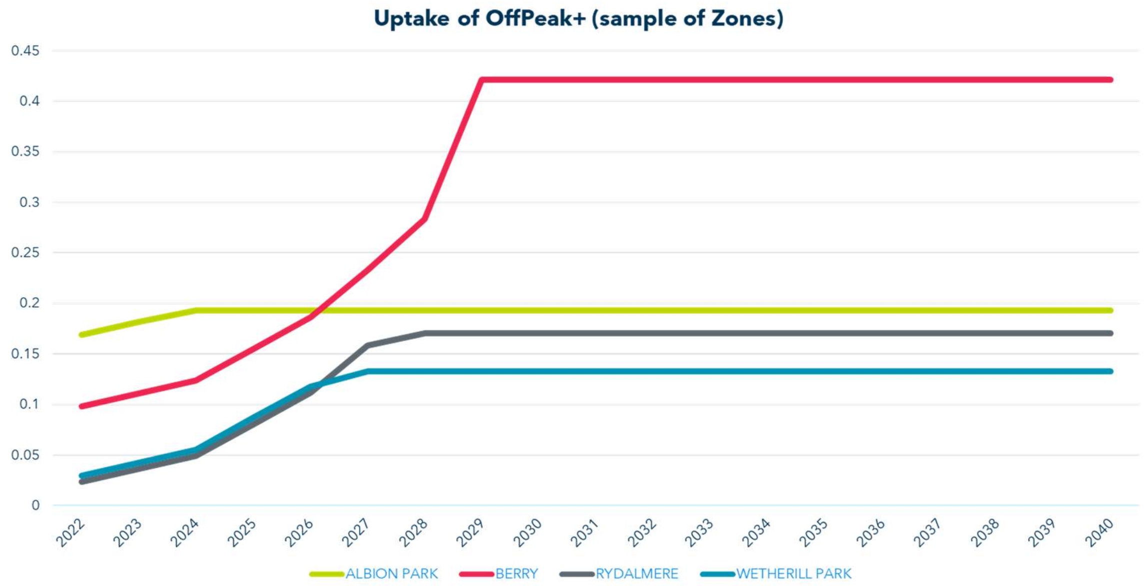


Figure 42 Yearly uptake of controlled load hot water solar soaking

Load Shifting Profile (Time of Day)

The price signalling results in a reduced night-time peak with energy moved into the off peak and solar soaking period as illustrated on the average day profile in Figure 43 below.

The shift profile in Figure 44 below is scaled to the daily kWh hour figure. It shows the increase of energy used in the early morning and midday and decrease of energy used in the evening peak hours. The impact of this load shifting can be seen in the underlying load profile in Figure 45 and then more broadly in the combined load profile in Figure 46

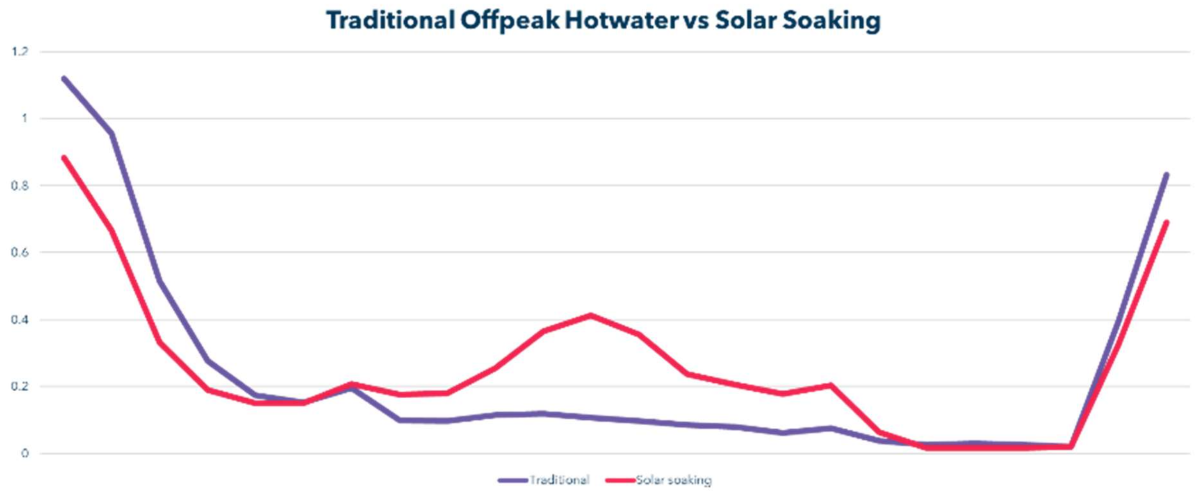


Figure 43 Average Time of Day Off Peak CL and Off Peak + CL profile

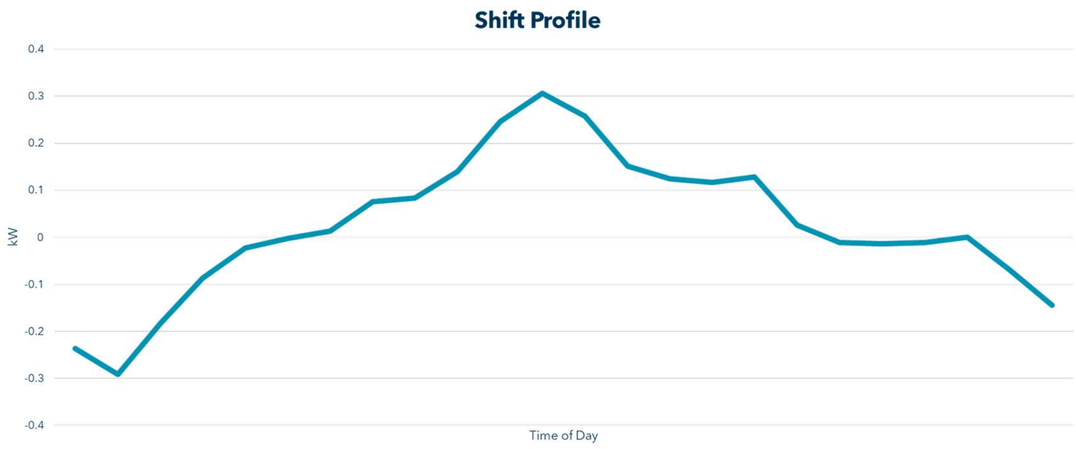


Figure 44 Shift profile from traditional off peak controlled loads to off peak plus controlled load

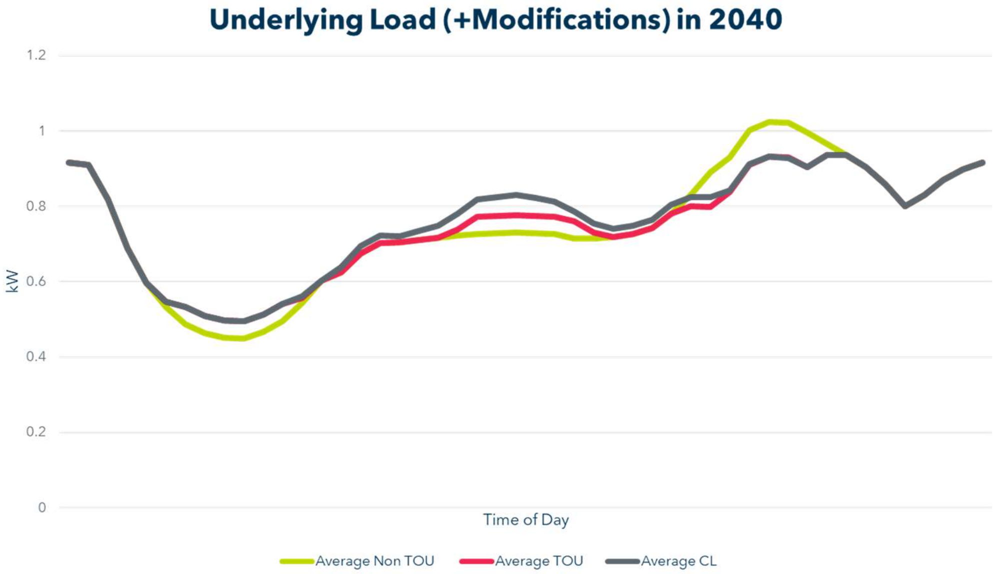


Figure 45 Underlying load + modifications to profile due to TOU tariff and Off Peak Plus CL

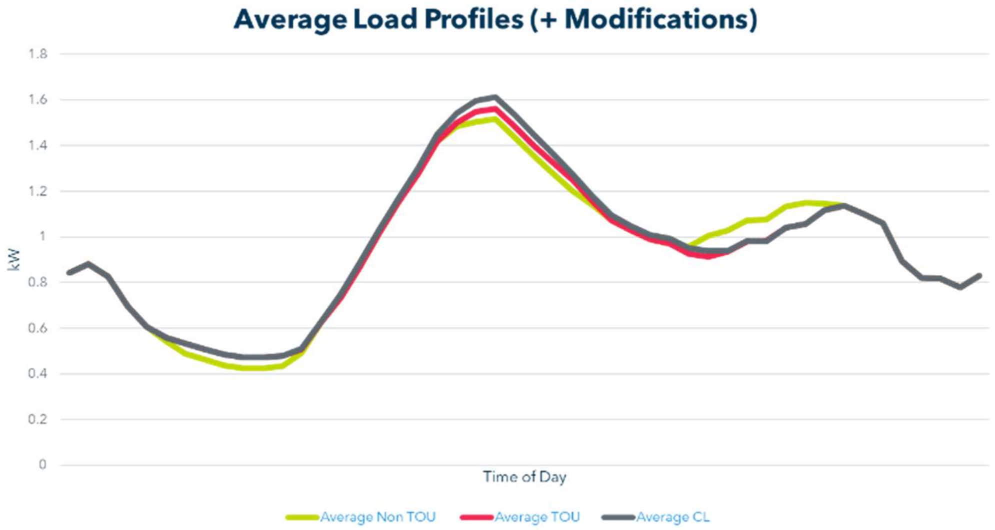


Figure 46 Adjusted average time of day load profile due to the adoption of a TOU tariff and Off Peak Plus CL (year 2040)

7.1.6 Dynamic Operating Envelopes

We have modelled the effect and benefits of DOEs on unlocking solar exports using a time series desktop model (workflow), The model uses time series irradiance data to model a PV system output, time series underlying load (as per our simulation models) to calculate an average solar customer net export. This export is then limited to 5kW as well as unconstrained. The delta between the energy exported is then the alleviation profile and valued using the time series CECV in the same workflow.

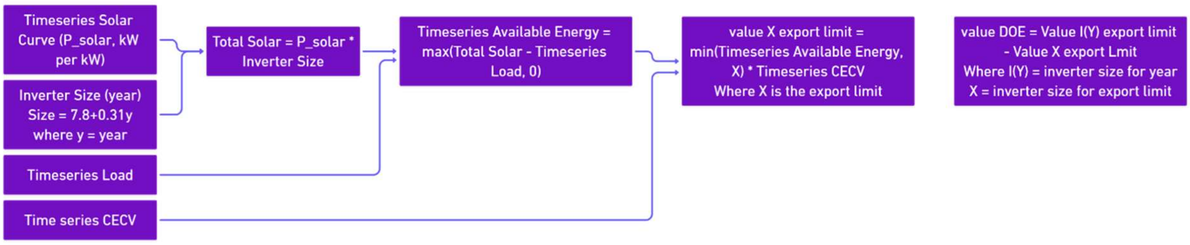


Figure 47 Workflow to Calculate Value of Export Limits

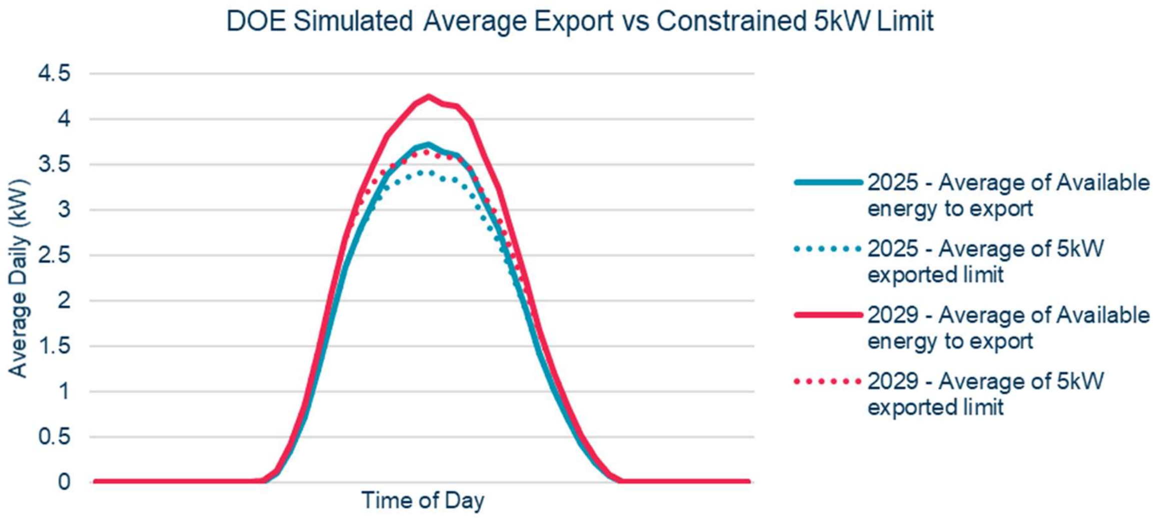


Figure 48 Simulated Average Export vs Constrained Export at 5kW Limit

Our Considerations for Implementing DOEs

Our average residential solar system size trend shows a clear linear growth trajectory towards larger systems. This has already exceeded on average our standard 5kW static limit. Our customers intend to continue to install larger solar systems and therefore our static limits will (and already are) becoming a constraint to this. Given the compliance to static limits is poor there is additional impetus to implement Dynamic Operating Envelopes which would improve compliance and equity of export access (reduce the number of customer's taking more than their "fair share").

8. Outputs

Recalling the objective of the modelling was to understand the potential constraints on the network as a result of DER uptake, sections 8.1 - 8.2 outline the measurements recorded during the modelling that are used to quantify the network constraints.

How is DER Inverter Curtailment measured?

Inverter curtailment is measured by taking running each simulation scenario twice. Firstly, with no inverter standards enabled and then secondly, with 4777.2.2015/2020 standards enacted.

The difference between kW output of panels (with no inverters enabled) and kW output of panels (with 4777.2.2015/2020 enabled), and then converted to kWh is the 'curtailment' experienced at a particular customer site.

How is DSUB Transformer Capacity measured?

Loading on the DSUB level is calculated as the aggregate of load from individual customers belonging to that specific DSUB. The result is a time-series loading profile for the DSUB. An aggregate is taken for summary data, looking at the minimum and maximum loading scenarios for that DSUB in any given year.

A report is prepared after the modelling is complete to identify the year in which a DSUB will reach:

- 50% reverse capacity,
- 80% forward capacity,
- 120% forward capacity

Note: this analysis assumes that all customers reach maximum at the same time - overlooking the diversity of load. However, this is counteracted by the fact that each customer is given an 'average' load profile which embeds a layer of diversity.

How is HV Feeder Capacity Measured?

Loading on the HV Feeder level is calculated as the aggregate of load from individual customers belonging to that specific HV Feeder. The result is a time-series loading profile for each HV Feeder. An aggregate is taken for summary data, looking at the minimum and maximum loading scenarios for that DSUB in any given year.

A report is prepared after the modelling is complete to identify the year in which a HV Feeder will reach:

- 90% forward capacity,
- 90% reverse capacity,
- 120% forward capacity,
- 120% reverse capacity

100% capacity aligns with EE's planning team's definition of capacity, i.e. 240A per HV Feeder.

Note: this analysis assumes that all customers reach maximum at the same time - overlooking the diversity of load. However, this is counteracted by the fact that each customer is given an 'average' load profile which embeds a layer of diversity.

8.1 Time-series output

Per LV feeder, timestamp and scenario, the following measurements are collected:

- Minimum and maximum voltages
- kW load/generation
- kVAR export
- Voltage Unbalance Factor (VUF)
- Curtailment in kWh
- CECV as per AER
- CECV as per Houston and Kemp analysis

8.2 Annually aggregated output

As with the time-series output, each LV feeder and scenario produces the below measurements however, the summary table takes a year-aggregated snapshot, rather than 30-minute time interval data.

- Absolute minimum and maximum voltages
- Minimum and maximum kW load/generation
- Voltage Unbalance Factor (VUF)
- Sum of curtailment in kWh
- Sum of CECV as per AER
- Sum of CECV as per Houston and Kemp analysis

9. Modelling Resources & Performance

9.1 Volume of Modelling

Load flow simulations are performed for the whole of the residential network. This equates to a volume of approximately 150 ZSs, 17600 DSUBS and 43000 LV feeders when filtering to specific criteria to optimise for efficiency and focus on the most likely problem areas on the network. The filtering excludes DSUBS from the modelling with:

- Less than 10m of mains connected
- Less than 2 Customer Connection Points (CCPs) attributed to the DSUB

This process is computationally expensive, as such, considerations regarding infrastructure were necessary to ensure runtime was within reason. Section 9.2 - 9.3 explores the infrastructure and software used for this modelling exercise.

9.2 Computing Hardware

The infrastructure used for the modelling process included 2 servers with the following specs:

- 64 Cores
- 128 GB RAM

Figure 49 Infrastructure used for the simulation tool

9.3 Computing Software

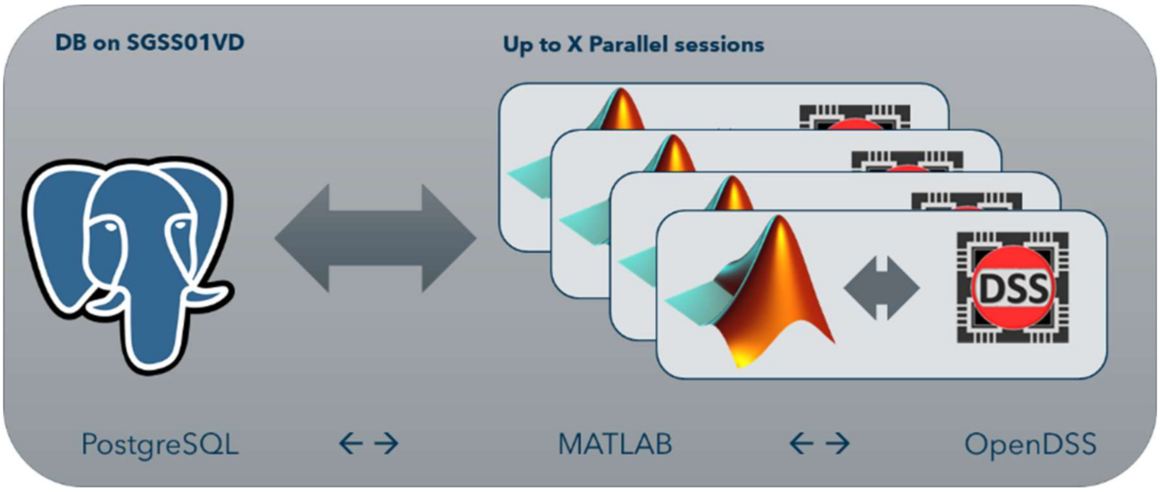


Figure 50 relationship between PostreSQL, MATLAB and OpenDSS

9.3.1 MATLAB and Parallel Computing Toolbox

MATLAB is used to create the model files for OpenDSS and to initiate the load flows. We utilised the Parallel Computing Toolbox within MATLAB to run simulations in parallel – reducing runtime significantly. In this way, runtime was proportional to the number of cores and amount of RAM that was accessible to us and therefore, could be continually improved with more resources.

9.3.2 OpenDSS

OpenDSS is an open-source platform capable of performing unbalanced, multi-phase power flow calculations. Through the common object model (COM) of OpenDSS it is possible to control OpenDSS circuit elements using an external software such as MATLAB. The software tool can produce 3-phase LV feeder network models using the available data from the database. This feature of the developed tool enables the user to analyse a large amount of LV distribution networks in a significantly reduced amount of time without the need to manually model the LV networks.

9.4 Model Performance

Runtime of the base case and alleviation options for all 18 years varies from ZS to ZS, ranging from 2 to 14 hours.

10. Appendix

Table 7 % Customers without a battery

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
% Customer's Without Battery	99%	98%	96%	95%	93%	92%	92%	91%	89%	87%	85%	83%	80%	77%	75%	73%	71%	70%

Table 8 Net behaviour shift as a result of impacting factors

Assumption Types	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Smart Meter Count	*300K*	*350K*	*400K*	*450K*	*500K*	*550K*	*600K*	*650K*	*700K*	*750K*	*800K*	*850K*	*900K*	*950K*	*1,000K*	*1,050K*	*1,100K*	*1,150K*
% Smart Meters	28.5%	32.6%	36.4%	40.1%	43.6%	47.0%	50.2%	53.3%	56.3%	59.2%	62.0%	64.6%	67.2%	69.7%	72.1%	74.4%	76.7%	78.8%
Assignment Policy	10%	70%	71%	72%	73%	74%	75%	76%	77%	78%	79%	80%	81%	82%	83%	84%	85%	86%
Retailer Pass Through	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	60%	60%	60%	60%	60%	60%
Customer's Fraction of Shiftable Load	1%	3%	5%	7%	9%	11%	13%	15%	17%	19%	20%	20%	20%	20%	20%	20%	20%	20%
Price response	1%	6%	11%	16%	21%	26%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Net Behaviour Shift as %	0.00%	0.00%	0.02%	0.07%	0.15%	0.30%	0.51%	0.73%	1.00%	1.32%	1.62%	1.86%	1.96%	2.06%	2.15%	2.25%	2.35%	2.44%
Net Behaviour Shift (kWh)	5.41E-06	1.44E-03	7.41E-03	2.24E-02	5.20E-02	1.03E-01	1.77E-01	2.51E-01	3.43E-01	4.53E-01	5.56E-01	6.41E-01	6.75E-01	7.09E-01	7.42E-01	7.75E-01	8.08E-01	8.40E-01