DER Integration Strategy

In support of the Energex 2025 – 30 Regulatory Proposal

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energex
Part of Energy Queensland

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1 OVERVIEW

1.1 Purpose

This document has been prepared as part of the 2025-2030 Regulatory Proposal with intention of meeting the requirements of the DER Integration Strategy. Distributed Energy Resources (DER) means different things in different contexts. In this context, DER should be taken to mean micro-embedded generators that export onto the network.

This document focuses on the initiatives and expenditure that we are proposing to undertake in enabling export services are provided efficiently and prudently to our customers.

1.2 Structure of this document

We have broken this document into four key parts:

- **Part 1: Our DER Integration Strategy** – this section outlines the principles we have utilised in developing our DER integration strategy. It highlights the drivers for investment or other interventions and summarises the investments that we have proposed for the 2025-2030 regulatory control period.
- **Part 2: Planning Framework** – this section outlines the ways that we identify network constraints and the value streams that we quantify to determine the most efficient level of investment in the interests of our customers. It also summarises the range of initiatives available to us in determining the solutions to our customers' requirements for DER integration.
- **Part 3: Forecasting Customers DER Requirements** – this section outlines how we have developed our customer export forecasts to enable us to analyse the level of investment or interventions required on behalf of our customers.
- **Part 4: DER Integration Cost Benefit Analysis** – this section outlines the cost benefit analysis we have undertaken for the key initiative areas to inform the investments and interventions that we have proposed in our regulatory proposal.

1.3 Compliance with DER expenditure guidance note

This document is prepared in line with the AER's DER expenditure guidance note. Table 1 summarises our compliance with this document.

Table 1 – Compliance with DER expenditure guidance note

Guidance Note	Relevant Section
Network Voltage Analysis	Sections 2.1, 4.5, 4.3, 4.8 outline how we approach assessing and resolving network voltage issues as a result of DER integration
DER penetration forecasts for the electricity distribution network over the medium to long term (at least 10 years) and the expected forecast demand for export services on network	Section 5 outlines our forecasting approach to DER integration. Supporting document Blunomy Distributed Energy Resource Forecast outlines our approach to developing our DER forecasts.
Evidence of how DNSPs will structure their tariffs to meet the forecast increase in demand for export services (supported by consumer behaviour modelling).	Section 6.3 includes an assessment of tariff structure and its impact on DER integration. Our Tariff Structure Statement (TSS) and Tariff Structure Explanatory Statement (TSES) further explain our proposed two-way tariff structures.
A clear summary of the various elements of DER integration expenditure, in terms of augmentation, ICT capex and opex.	Section 2 and section 6.6 outline our elements of DER integration.
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	Sections 2.2, 4.6, 6.4 and 6.6 outline our approach to DOEs.
Details of activities undertaken and actual expenditure in the current regulatory period to manage DER integration	Section 3 and Section 4 outline the way we have valued DER integration investments and the initiatives we have undertaken to date.
Transparent references to expenditure items in the reset RIN	See 7.8 Export Services tab in the Reset RIN

Part 1 - Our DER Integration Strategy

2 OUR DER INTEGRATION STRATEGY

Energex is committed to energising Queensland communities by working together towards empowering an 'Electric Life' for our customers, and to transforming the energy system to meet future needs. This commitment is about enabling customers choice over their energy supply and usage, supporting the deep electrification of homes and businesses, and support the transition to a net zero emissions future.

We have two competing elements to balance when integrating DER into our network:

- Enabling customers to maximise their resources for both their benefit, and for the benefit of all customers,
- Utilising our existing assets to ensure efficient investment in the network, maintenance of our power quality obligations and ensuring asset utilisation is high, maximising value for our customers.

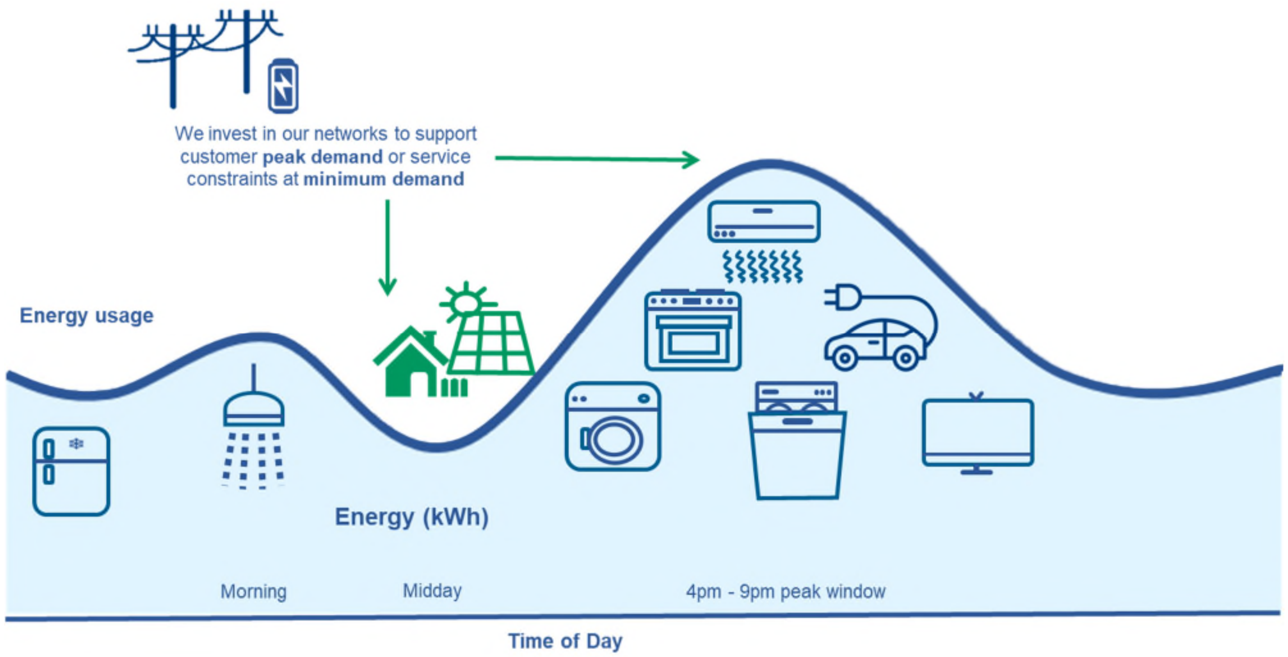
Figure 1 shows the balance we are trying to achieve through our DER Integration Strategy.

Figure 1 – Considerations in integrating DER

2.1 Drivers for Investment

In considering the integration of customer export, we undertake a thorough process to forecast customers uptake of DER, as well as assessing our existing networks capability to host the export that could come from our customers assets. It is important to understand that the volume of embedded generation is not necessarily a driver of network investment, rather it is the outcome of maximum and minimum demand that drive investment. There is generally a direct link between the volume of embedded generation and the minimum demand on our network. Figure 2 outlines the challenges in planning our network for the challenges of minimum and maximum demand.

Figure 2 – Typical Day Demand Curve



In considering investment on the network for export services, there are two main challenges – asset capacity and network voltages.

- **Asset Capacity** - As our minimum demand continues to decline and turns into minimum demand and reverse power flows, our assets need to be able to provide the required thermal capacity to cater for export. This problem has always existed for peak demand and is simply a reflection of the rating limitations of our assets. When the forecast flows through our assets are greater than the rating, we need to consider an intervention to avoid overloading our assets.
- **Network Voltage** – In catering for an increased export from customers' export assets, power quality issues such as voltages outside the technical limitations on our networks become an issue for us to manage. This becomes particularly difficult as the difference between the peak and minimum demands become more pronounced, managing network voltages to ensure we don't have voltages below technical standards at peak demand, and voltages above technical standards at minimum demand becomes difficult on LV networks because of our limited active voltage control on these networks.

2.2 DER integration

Our approach to providing export services to our customers is to provide customer choice while ensuring that the costs associated with providing this service falls to those customers utilising the network for export. Our strategy has seven key initiative areas that ensure this outcome:

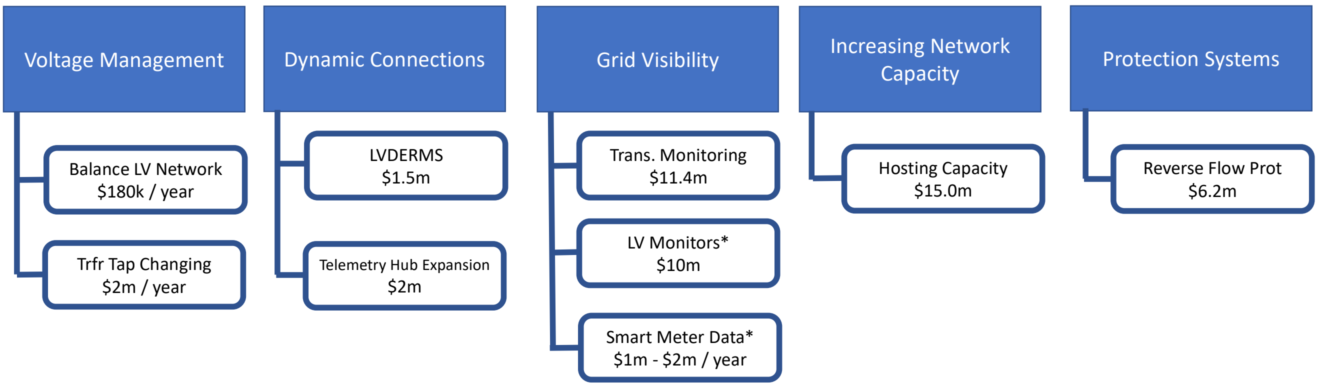
1. **Tariff design** – through consultation with customers in our Voice of the Customer forums we have designed a set of tariffs that will increase our customers' ability to make use of their assets, as well as improving our ability to manage the differences between our minimum and maximum demand.
    - Enhancing our time-of-use tariffs will continue to encourage our customers to use energy through the middle of the day, reducing our minimum demand issues on the network.
    - As part of our Tariff Structure Statement (TSS), we have proposed an export pricing structure that gives customers choice on how they interact with the network. Customers will be able to choose to opt-out of two-way tariffs charging if they connect to a dynamic connection (which allows us to control export within network limits) or be assigned to two-way tariff with both charge and reward should they choose to have full control over their own exports.
    - A Basic Export Level (BEL) of 1.5kW, which is the threshold below which a retail customer can export to the network without incurring a charge and the level of export that we will guarantee all customers connecting to our network.
2. **Demand management** – our customers have trusted us to be able to manage our peak and minimum demand through our extensive controlled load capability. Utilising this load control to "solar soak" hot water and other controlled load through the middle of the day reduces the minimum demand challenges that we could otherwise have without this capability. We will continue to utilise this capability to ensure we maintain or increase the utilisation on our existing assets. The cost of this initiative is effectively zero cost as we are utilising our existing capability in a different way. Because of this we have assumed this to be in place in our analysis and that this will continue to be implemented in the 2025-2030 regulatory control period.
3. **Voltage management** – we will continue to ensure customer compliance with inverter standards and have active programs of LV tap changing and phase balancing as a low-cost way to alleviate curtailment due over-voltage challenges caused by high-penetration of export, allowing for higher levels of export on our network and a fair share of network usage for all of our customers.
4. **Dynamic connections** – we will continue to implement dynamic connections and dynamic operating envelopes (DOE) to ensure that customers have full access to our network capability to maximise the utilisation of our assets and reduce costs for all customers. We will still provide customer choice in having a fixed connection arrangement through the provision of two-way tariffs.
5. **Grid Visibility** – where appropriate and required, we will increase the level of data we have on our LV networks to ensure we can effectively manage the uptake of export services on our system and accurately calculate network constraints to reduce curtailment and increase the benefits for those customers that are able to export onto our network.
6. **Traditional Network Investment** – where we can't provide a sufficient level of network capacity to our customers in line with the value of their exports to the grid, we will upgrade our network size to increase its hosting capacity. The drivers for this investment are either where

the level of curtailment is significant enough to warrant alleviation under a cost benefit analysis, or where we are required to upgrade our network to ensure that we can provide a Basic Export Level (BEL) of 1.5kW.

7. **Reverse Flow Protection Systems**: as export continues to increase and assets see negative minimum demands, some of our protection systems that were only designed for forward load flows require upgrading to ensure they are still able to isolate faults, providing a safe network for our customers and the community.

Figure 3 outlines the investment streams as part of the 5 initiatives that require us to invest in managing the network. Our Tariff design and Demand Management initiatives don't require us to directly invest and so are not included in Figure 3.

Figure 3 – Investment Streams for DER Integration



As Figure 3 shows, most of our investment is in Grid Visibility, maximising our customers use of our existing assets. Our investment in increasing the network is the next largest contributor, ensuring that we efficiently unlock export services for highly constrained network areas.

While this document outlines our strategy for integration of DER, the cost benefit analysis associated in Part 4 focuses on the justification of the LV DERMS, Telemetry Hub, Transformer Monitoring and Hosting Capacity elements of our capital expenditure, and the Voltage Management elements of our operating expenditure. This cost benefit analysis provides benefits streams for the other investments in DER integration, the justification of the other expenditure is covered in other business cases that are available on request.

Table 2, Table 3 and Table 4 on the next page summarise the elements of expenditure that are justified through the cost benefit analysis included in this strategy, the expenditure that is included in our opex forecast, and the capex which is justified in other business cases.

Table 2: Summary of DER integration Capex expenditure included in this strategy

Expenditure Type	Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Dynamic Connections	LVDERMS	1.23	0.25	-	-	-	**1.49**
	Telemetry Hub Expansion	0.93	0.93	-	-	-	**1.86**
Grid Visibility	Transformer Monitoring	2.28	2.28	2.28	2.28	2.28	**11.40**
Increasing Network Capacity	Network Upgrades for DOE connected customers	-	0.50	-	-	0.50	**1.00**
	Network Upgrades for non-DOE connected customers	1.70	4.24	4.68	1.71	1.71	**14.03**

Table 3: Summary of DER integration Opex expenditure included in our total Opex forecast

Expenditure Type	Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Voltage Management (opex)	Balance LV Network	0.2	0.2	0.2	0.2	0.2	**1.0**
	Transformer Tap Changing	2.0	2.0	2.0	2.0	2.0	**10.0**
Smart Meter Data[1] (Step Change)	Acquiring and using smart meter data.	2.0	2.4	2.8	3.1	3.5	**13.7**

Table 4: Summary of DER integration Capex expenditure in other business cases

Expenditure Type	Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Protection Systems	Reverse power flow protection upgrades	0.93	1.37	0.72	1.82	1.30	**6.13**
LV Monitors[2]	Service line LV monitors	1.90	1.90	2.00	2.00	1.80	**9.50**

[1] This expenditure is covered in Attachment – Smart Meter Data Acquisition
[2] This expenditure is covered in Attachment – Smart Meter Data Acquisition

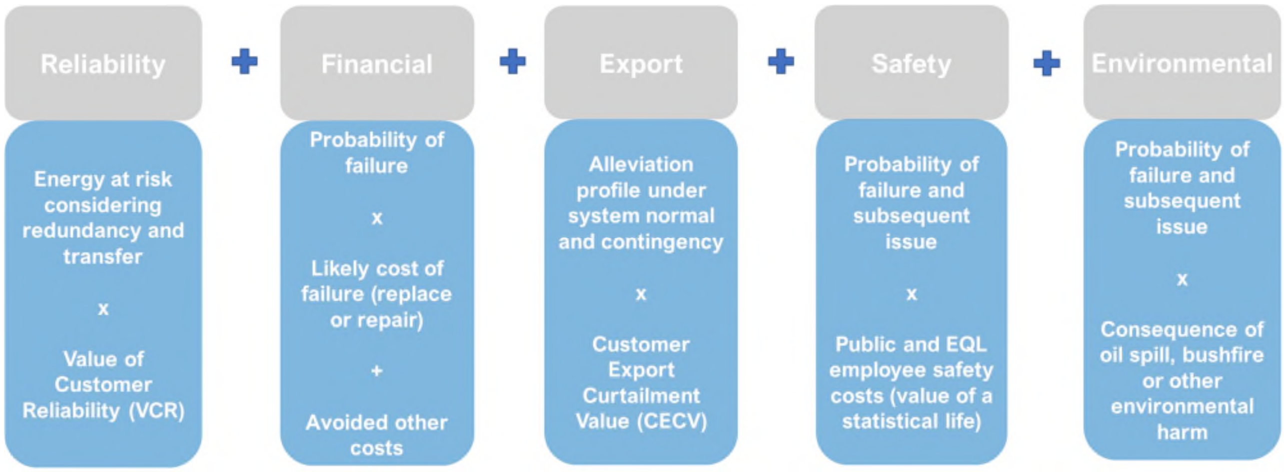
Part 2 - Planning Framework

3 PLANNING FRAMEWORK

3.1 Value Streams

In addition to any mandatory investments driven by legislative compliance, Energex utilises five value streams in assessing the benefits of undertaking an investment in the network. Figure 4 outlines these value streams.

Figure 4 – Value Streams for Cost Benefit Analysis



In assessing investments for integrating DER for our customers, the main areas we have valued are:

- **Financial** – the difference in network expenditure from implementing strategies to integrate export services. This includes deferral of network upgrades to cater for extra solar, to investing in network monitoring to better understand our network constraints arising from minimum demand.
- **Export** – the level of curtailment in our network varies according to network conditions and the interventions we implement. This is valued utilising the Customer Export Curtailment Value (CECV), which allows us to compare the benefits of alleviating curtailment against the cost of lost export that customers would experience without interventions.
- **Environmental** – the level of curtailment under the options we have considered also has an impact on carbon emissions, given most of the export we are forecasting on our network is renewable energy. As such, we have considered this impact in our cost benefit analysis for the integration of export services.

3.2 Basic Export Level

The basic export level is the threshold customers can export without charge and is a level of export that Energex will ensure is always available to customers. Where network constraints occur, Energex will make investments to maintain this capability in the network. Energex has undertaken an analysis of our network capability and our subsequent capability to deliver on a basic export level for customers. Figure 5 and Figure 6 show the percentage of HV feeders and distribution transformers that should customers currently without PV installed a system, the BEL shown in the chart would be able to be accommodated.

Figure 5 – HV Feeder Remaining Capacity

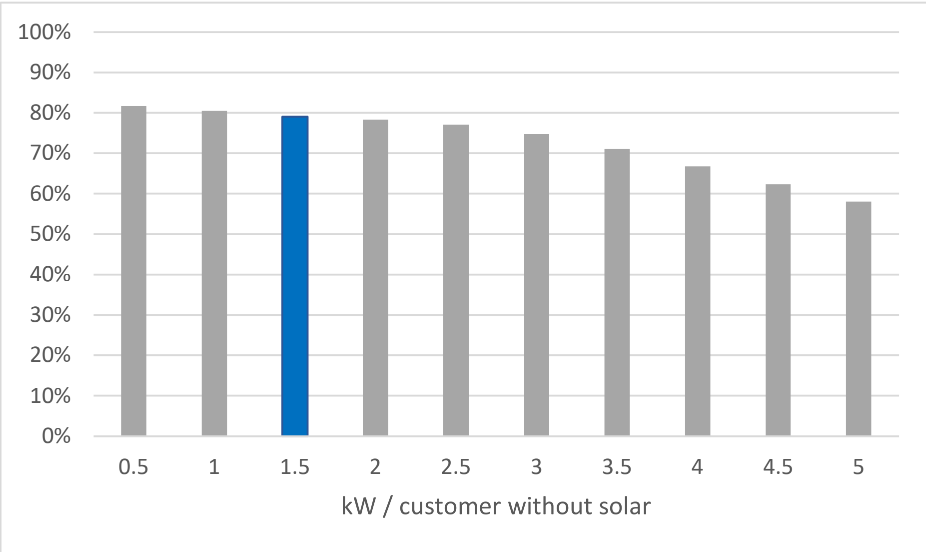


Figure 6 – Distribution Transformer Capacity

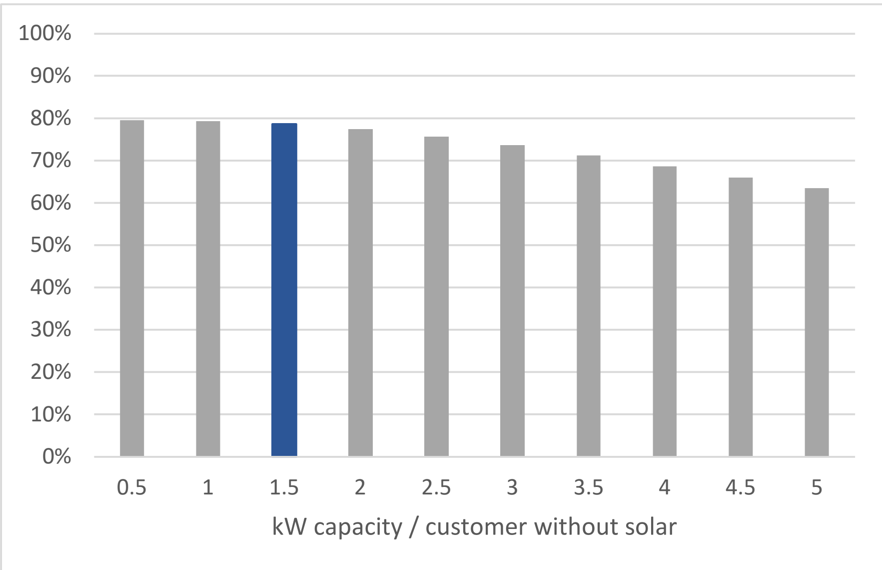


Figure 5 and Figure 6 both demonstrate that there is that the percentage of our assets that can accommodate a BEL starts to decline more dramatically at the 1.5kW level. Figure 7 outlines the investment implications for setting the BEL between 1.5kW and 3kW at different take-up rates.

Figure 7 – Investment Requirements for BEL

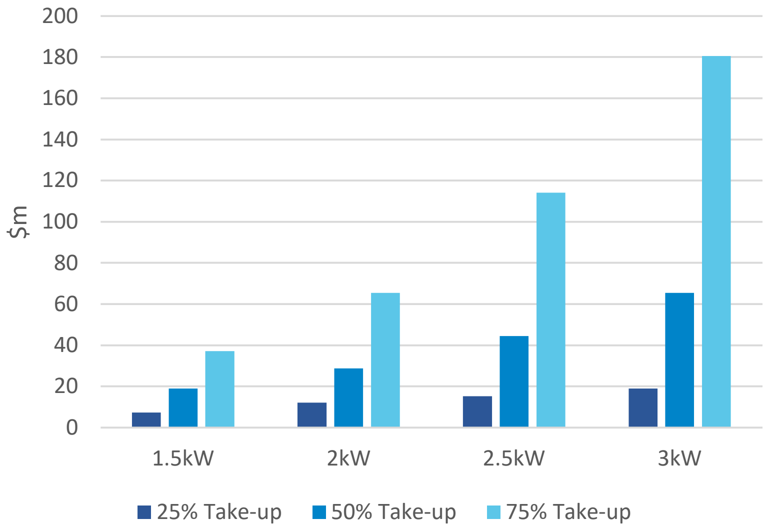


Figure 7 shows that the difference between investment requirements between a take-up rate of 25% and 75% of customers without solar is significantly less at 1.5kW than 2kW. There is a tipping point in both capacity and subsequent investment that occurs at around 1.5kW.

As a result, Energex has proposed to set the BEL at 1.5kW. We have balanced the need for the required level of investment to ensure this is provided to customers while ensuring that the existing capacity in our network can be utilised by the connection of customer with sufficient capacity in their network to be able to export to the grid. With a forecast increase in export customers in the 2025-2030 period of around 25%, providing a BEL of 1.5kW will result in network investment of around $7.3m, which involves increasing distribution transformer and HV feeder capacity.

3.3 Customer Export Curtailment Value (CECV)

In assessing the need for investment to integrate export into our network, we make use of the AER published CECV's. Curtailment of DER refers to where the level of export is reduced or eliminated because of the prevailing network conditions. This can happen because of high voltages which causes a customer's inverter to reduce output, or where a customer has connected under a Dynamic Connection and has allowed us to reduce the output of their solar system due to network constraints of either voltage or capacity. While curtailment allows the network to operate within its limits without the need for network investment, it is important to consider the value of the lost export for our customers. The CECV allows us to assess this lost energy as a value to consider the optimum point for investment.

We have developed a model for forecasting potential CECV which incorporates our forecast export penetration, resultant minimum demand, asset capacity, voltage constraints and network visibility constraints. Our modelling has a three-step approach:

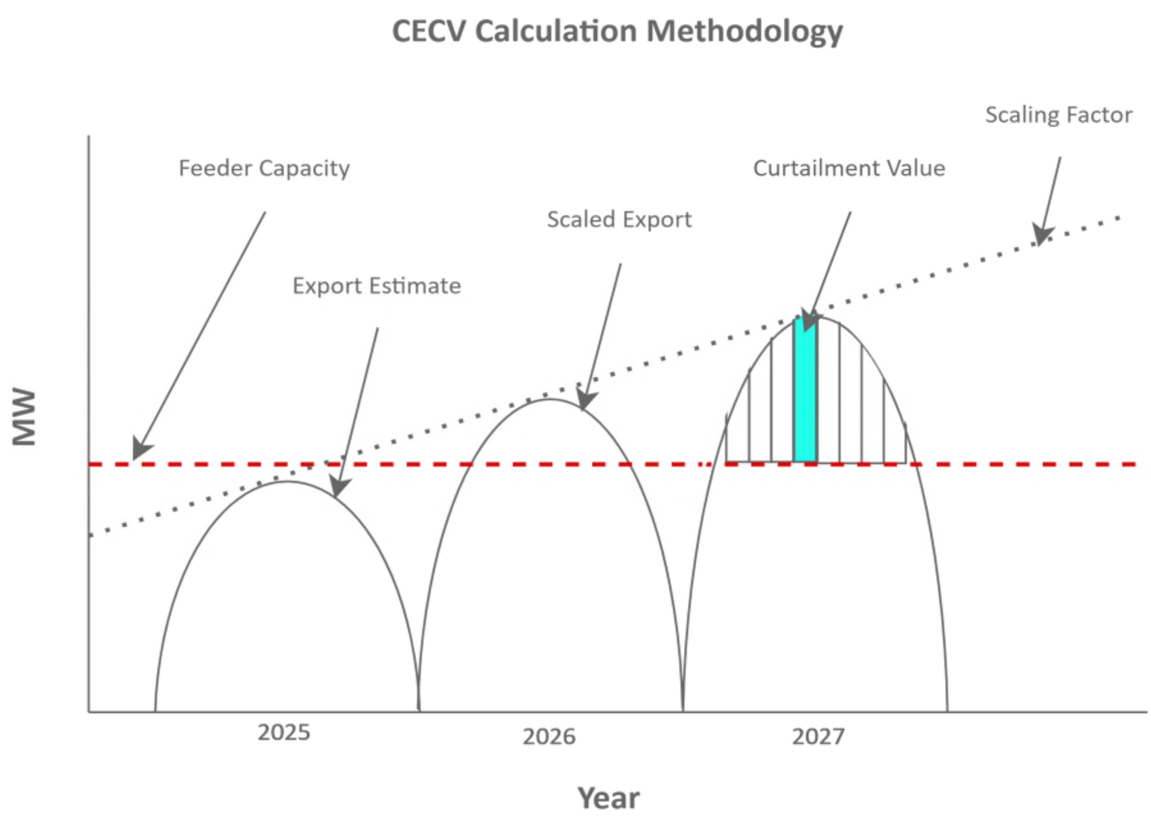
1. We start by creating minimum demand forecasts for all distribution transformers and feeders in our network.

2. An average yearly 30-minute load curve has been derived from a selection of our most representative feeders. This gets scaled to the level of minimum demand that has been determined at the Distribution Feeder and Transformer level from our forecasts.

3. The level of MWh curtailment is determined on a half-hourly basis for the time horizon being assessed, with the corresponding CECV utilised to determine the value of the curtailed export.

Figure 8 provides a stylised demonstration of the steps above.

Figure 8 – CECV Calculation Method



In assessing the interventions, we have available in integrating DER into our network, the CECV has been calculated for all the feasible options where curtailment occurs as a cost to be weighed up against alternative options to ensure that we provide maximum benefits to customers in our business cases.

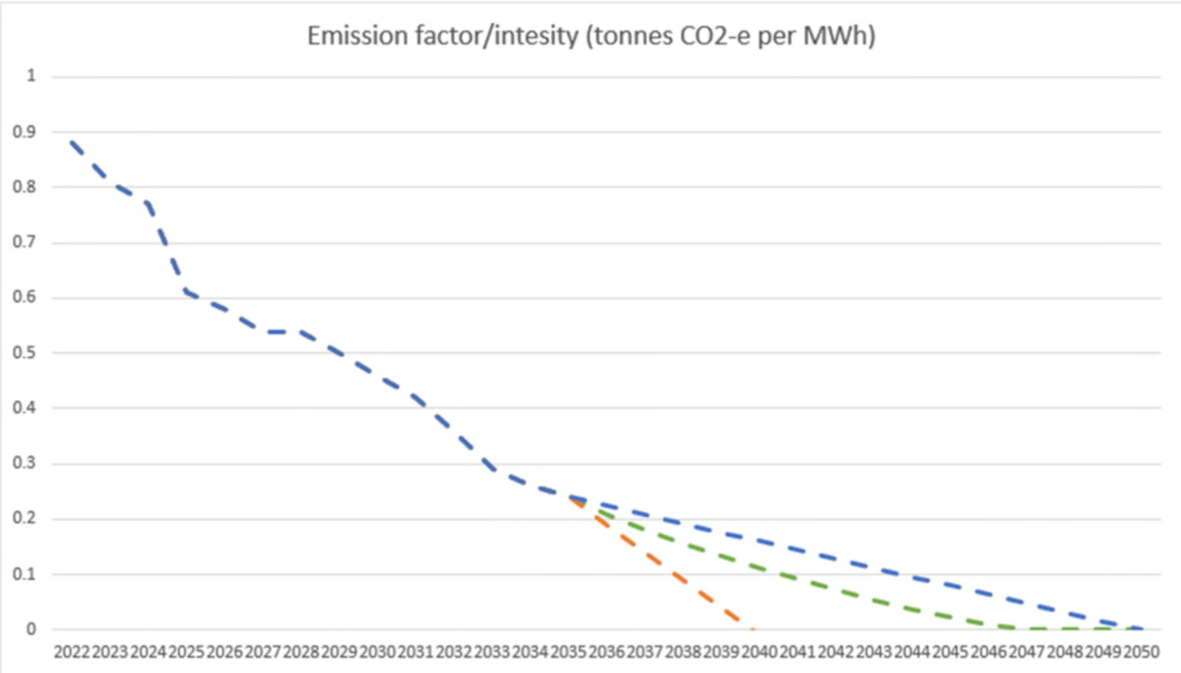
3.4 Emissions Reductions

The National Electricity Objective has recently incorporated emissions reductions. As such, we have incorporated emissions reductions into our DER integration cost benefit analysis as a value stream. There are two considerations in assessing the value of carbon emissions abatement:

1. Carbon Price – we have assessed a variety of materials and have utilised a carbon price of $35 / tonne, which is around the ACCU spot price at the time of writing. In assessing the trajectory over time, we have considered the IPCC and EPA assessments of an increase in the social cost of carbon over time. In utilising these sources, we have estimated an increase of around $1 / year in the carbon price.

2. Emissions Factor – in determining the emissions factor, we have utilised the trajectory suggested by AEMO, with a range of futures beyond 2035 considered for those investment cases that require a longer period. Figure 9 outlines the trajectory of the emissions factor for the Queensland electricity network.

Figure 9 – Emission Factor of the Queensland Energy System



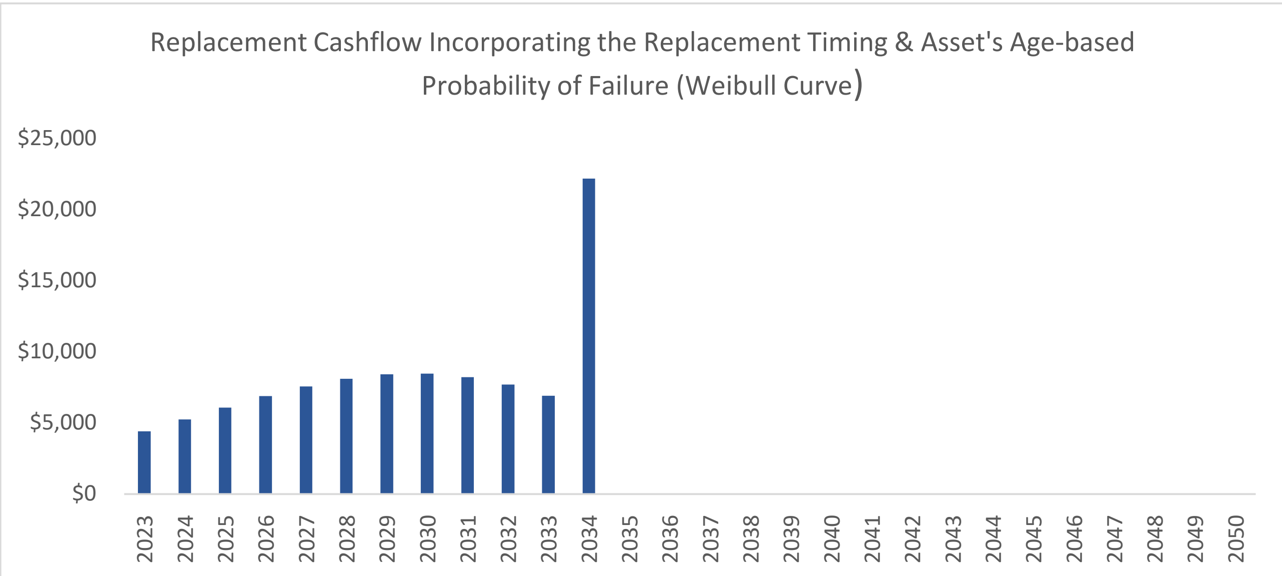
3.5 Avoided replacement for condition

As our assets age, the likelihood of them being required to be replaced increases. This is important to consider in the context of network constraints, as an asset replacement is an opportunity to increase the capacity of the network where constraints may be emerging. In the context of DER integration, this is particularly prominent in considering distribution transformer replacements as these assets are generally the most impacted by increasing export, but also have a higher replacement cost for asset condition type issues.

As part of our Transformer Replacement business case, we have determined an age-based probability of failure model to determine the level of investment we require for distribution transformer replacements. In assessing our need to invest based on DER integration, we have utilised this model to determine the relative likelihood of a transformer replacement in the areas we identify as requiring increased capacity for export. This determines a portion of cost for each distribution transformer that we forecast requiring increased capacity for export at some point in time, to ensure that we aren't factoring benefits and costs associated with DER integration that should fall to our replacement expenditure.

Figure 10 demonstrates an example of the approach, showing how we have factored in a small proportion of replacement expenditure in the years before we have forecast the capacity upgrade.

Figure 10 – Demonstration of Replacement Cashflow in Transformer Upgrade



It is important to note that we have assumed that any asset replacement results in a capacity upgrade that can resolve any network constraints for export services. This is a conservative approach that understates the costs associated with network upgrades, given not all asset replacement can result in a capacity upgrade.

3.6 Avoided capacity increase for load growth

In assessing the need for network investment to enable export, it is important to consider the likelihood of increased network capacity because of load growth. In simple terms, if minimum demand growth in our network requires us to increase the capacity of our distribution feeders and transformers, then our ability to host export will also increase. We have factored this increased capacity to host customer load into our modelling. There are three general results of including this into our analysis:

1. **Avoided investment** – where our modelling shows a constraint for peak demand occurs prior to a constraint for minimum demand, we assume that an investment has taken place that increases the hosting capacity for minimum demand. While this may not always be the case, we have taken this approach as the more conservative view to ensure that any investment to integrate DER is clearly in the customers benefit.

2. **Bring-forward investment** – where our modelling shows a constraint for peak demand occurs after a constraint for minimum demand, we only factor in the bring forward costs of this investment in our modelling works for DER integration.

3. **No impact** – most of the constraints that we have identified as a result of excess export occur on assets where there are no forecast peak demand constraints. No impact occurs on these assets in our assessment of DER integration.

In assessing the impacts of peak demand investment, it is important to understand how we have determined constraints in our network because of peak demand.

4 KEY INITIATIVES

4.1 Tariff design

Network Tariffs play two important roles in DER integration. The first is to encourage customer energy use to match time periods where we have sufficient load or export hosting capacity to increase asset utilisation. The second is to fairly charge customers for use of our network.

Since July 2021 all Energex Residential and Small Business customers with access to a smart meter by default have been assigned to a demand-based network tariff that encourages customers to avoid the evening peak period (4pm to 9pm). These Customers also have the option to select a time-of-use solar soak tariff with price incentives to use more energy during the day when the sun is shining.

Both network tariffs reflect the different times of use when network cost drivers are high, considering peak and minimum demand periods. This approach to networks tariffs incentivises customers towards more flexible load profiles, either through customer choices or technology (e.g. household timers).

Energex customers also benefit from load control or economy tariffs (often referred to by their retail tariff names Tariff 31 or Tariff 33) that offer a low network price in return for allowing the Network to control when the load is switched on and off.

The introduction of two-way network tariffs further builds on these price signals/network cost drivers by rewarding Customers that choose to export during peak periods, thus reducing the need for further network investment. Such export would result in credit applied to the network portion of their bill. Two-way network tariffs also support the use of a network charge where customers choose to export during periods of minimum demand without a dynamic connection.

4.2 Demand management

Demand Management (DM) has played an important role in Queensland for several decades and Energex has a regulatory requirement under section 127C of the Queensland Electricity Regulation 2006 to consider demand side options We publish our Demand Management Plan (Plan) on our website each year, which is also an attachment to our proposal.

Our DM Program includes the well-established Broad-Based initiative which rewards hundreds of thousands of customers across the network for their demand flexibility through secondary tariff enabled load control. Our current secondary load control network tariffs make supply available to residential and small business customers at a lower energy rate for a specified number of hours a day. They are mostly used for hot water heating and pool pumps. In return, Energex can control when the supply is made available. Currently 41% of Energex customers have their hot water systems on load control tariffs.

This control is implemented through our Audio Frequency Load Control (AFLC) system or through timers in areas where AFLC is not available. This system enables Energex to aggregate demand response from connected loads, at zone substation level for the benefit of the network. It is a key tool for improving network utilisation.

Our summer network peak demand continues to grow – and having the ability to temporarily manage supply to appliances that may be operating during those high network demand period helps reduce those peak events and the risk of blackouts. Similarly, after successful trials, we are also utilising the load control system in “solar soak” schedule (typically in autumn and spring) when there is excess rooftop solar generation, and lower customers energy use, on the wider distribution network. The 'solar soak’ schedule shifts the operation time of remotely controllable appliances, such as hot water systems on controlled load tariffs, from earlier in the day to the middle of the day when distributed PV output is typically highest and helps to address minimum operational demand issues.

Based on the successful testing, these ‘solar soak’ switching schedules will be used every autumn and spring when minimum demand issues typically occur, or otherwise as required. The maximum per hot water system diversified benefit, when a ‘solar soak’ schedule is implemented is estimated at 0.41 kW for economy tariff (Retail T33) and 0.80 kW for super economy tariff (Retail T31). This equates to around 0.26kW on a diversified basis at the distribution transformer level.

4.3 Voltage management

In October 2017, the Queensland Electricity Regulation was amended to change the Low Voltage from 415/240 V +/-6% to 400/230 V +10%/-6% to harmonise with Australian Standard 61000.3.100 and a majority of other Australian States. In January 2023 the Australian Standard changed the LV lower limit to -10% and as a result the Queensland Electricity Regulation changed. Energex is therefore required to manage the voltage on LV circuits within a tolerance of 230 volts +10%/10% (250 volts to 207 volts).

While the new inverter standard provides more active voltage control on our LV networks, it is important to understand that inverters installed prior to this do not provide this active level of control, and generally manage overvoltage through a dramatic decrease in Watt output, or even an overvoltage trip and total loss of export. Furthermore, our modelling assumes that there is still a reduction in output of around 5% for new inverters to manage the voltage at their connection point.

As such, there is still a significant part for LV voltage management to play in integrating DER into our network, with the benefits being a reduction in curtailment which will be calculated using the CECV. This typically involves:

- Changing tap settings on a distribution transformer.
- Changing the network configuration on LV networks to adjust the connection points to an adjacent LV feeder which has more hosting capacity.

Installing active voltage management such as voltage regulators on the LV or more likely MV network.

4.4 Connections Compliance

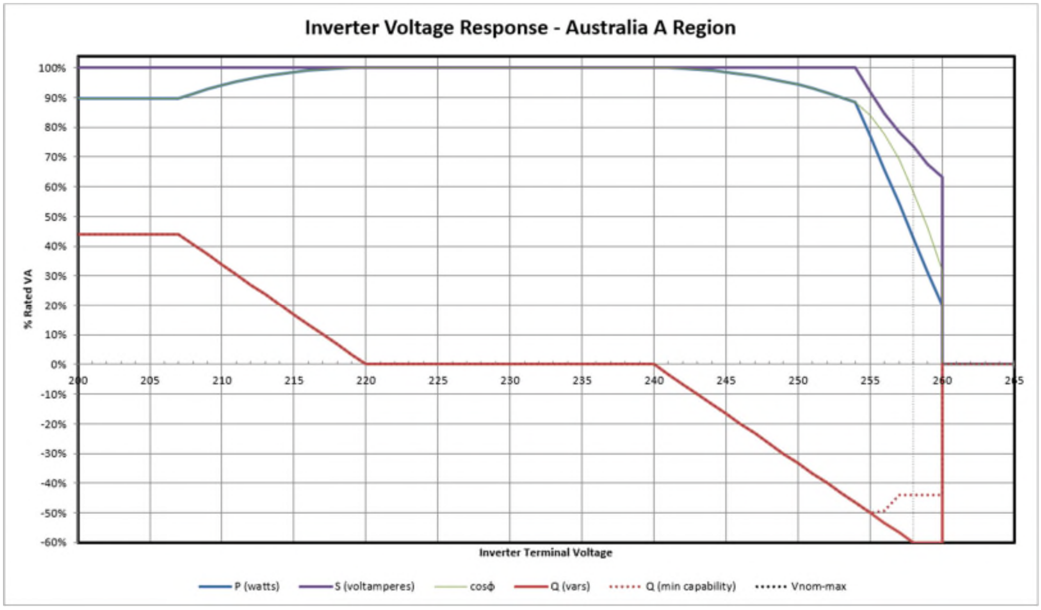
One key step in ensuring that we can integrate DER in the most efficient way to maximise the benefits for all our customers is to ensure that customers installing their own embedded generators are compliant with the relevant standards and our Connection Policy and their Connection Agreement. As discussed earlier, there are two main factors in assessing our hosting capacity – thermal capacity and power quality.

Capacity limitations on customers' exports are set in our Connections Policy, and these limits flow through to our export services uptake and minimum demand forecasts. They are well understood by customers and are easily enforced through our connections processes. We will discuss Dynamic Connections in Section 4.6. What is important is compliance with existing inverter standards, and the impact of customer inverter capability on the network, and the way we integrate DER into our network.

4.5 Inverter Compliance

In December 2020, Australian Standards released a new version of AS/NZS 4777.2 Grid connection of energy systems via inverters Part 2: Inverter requirements. The update saw a range of changes to improve the performance of inverters on the electricity supply network. These changes will support the continued increase of solar PV, batteries, and electric vehicles. The main impact on managing distribution network constraints is the requirement around voltage control at the inverter, and in particular volt-var control. Figure 11 outlines the voltage response requirements set out by this standard.

Figure 11 – Inverter Voltage Response Compliance Requirements



The impact of this standard change is that all new inverters will have volt-var and volt-watt control to help manage the voltage at their connection point, which will in turn help us manage the voltage in our LV networks to the advantage of all customers. As Figure 11 outlines, the standard requires inverters to gradually increase reactive power absorption from 240V to help mitigate voltage rise associated with active power export. Above 253V, the volt-watt response restricts the maximum active power output causing an increased reduction in Watts to continue to manage voltage.

In this way, as the uptake of systems with inverters compliant with the new standard increases, we will see improved voltage profiles on our networks while also seeing a relatively steady output of Watts from customer systems. This in turn means that the occurrence of voltage constraints in our networks is less likely to increase despite growth in exports, however with increasing exports, thermal constraints will appear on our networks where exports exceed the thermal capacity of our assets. Ensuring compliance with the new inverter standards will see our focus shift from managing voltage constrained networks to more of a need to focus on capacity constrained networks.

4.6 Dynamic connections

A dynamic connection is a type of connection where customers allow Energex to provide a flexible export limit for their DER systems. This means that exports can be higher during periods where our assets can provide the capacity and reduced where there are constraints on our network. Historically, because we were unable to limit export at times of constraint, and had limited visibility of DER output, our connection processes generally limited customer export to 5kW/phase. Where dynamic connections are available, we will be able to increase this capability to 10kW/phase, while guaranteeing customers an export at any time of 1.5kW.

In this way, the introduction of dynamic connection agreements will improve network utilisation through being able to manage export to network constraints, enable greater access to DER for customers through increased export capacity, and allow households and businesses to access new and emerging market opportunities as they become available.

Energex has invested in dynamic DER connection management through the development of the Distribution System State Estimation (DSSE) and the implementation of a Distributed Energy

Resource Management System (DERMS) to apply Dynamic Operating Envelopes (DOE) to DER on feeders with constrained hosting capacity. These DOE's will be feeder and transformer dependent, and so curtailment will only occur on a site-specific basis to maximise customer benefit and network utilisation.

4.7 Network monitoring and visibility

Network monitoring and visibility refers our ability to determine the energy flowing through our network at a given point in time. Historically, we have had good visibility at the higher voltage elements on our network, however limited to no visibility at our lower voltage equipment. As the penetration of DER continues to increase, the ability to monitor the energy flows on our network becomes more important to determine network constraints and the power quality implications for our customers. The methods of obtaining "visibility" include:

- acquisition of telemetry from dynamic connections
- acquisition of Smart Meter data
- installation of service line monitors
- Installation of distribution transformer monitors
- derivation of synthetic (calculated) grid visibility data where telemetry is unavailable.
- evolution of near real time data platforms

In the context of the integration of DER, increased visibility and monitoring of the network provides three main benefits:

- **Power Quality:** Greater ability to understand and respond to power quality issues on the network because of an increase in DER penetration.
- **Reduced curtailment**: In concert with our dynamic connections, we can limit our need to curtail customer export. Without visibility, we need to estimate export levels and so must take a more conservative curtailment approach to ensure we don't damage our network.
- **Optimum investment timing:** If we weren't to enable customers to take up dynamic connections, we would be unable to curtail customer export at times of constraint. Without the capability to curtail, we would be required to invest in network capacity to avoid equipment damage from export above our asset's capability. While this could be done through estimation of the state of the network, visibility enables us to make more informed decisions about when we are approaching our networks capability.

It should be noted that there are benefits to customers from improving our network monitoring and visibility capability apart from the integration of DER. These include safety and reliability benefits from being able to determine faults in our network and respond more quickly to restore supply. These are outlined in supporting document Smart Meter Data Acquisition Business Case, outlining our justification for smart meter data acquisition and LV monitoring requirements.

4.8 Increasing network capacity

Once alternative options have been considered and factoring in the CECV and carbon emissions values resultant from curtailment, we will invest in network capacity upgrades to increase hosting capacity once curtailment reaches a critical point at which the costs of export reduction are higher than the costs of network upgrades. Figure 12 shows a stylised version of this assessment,

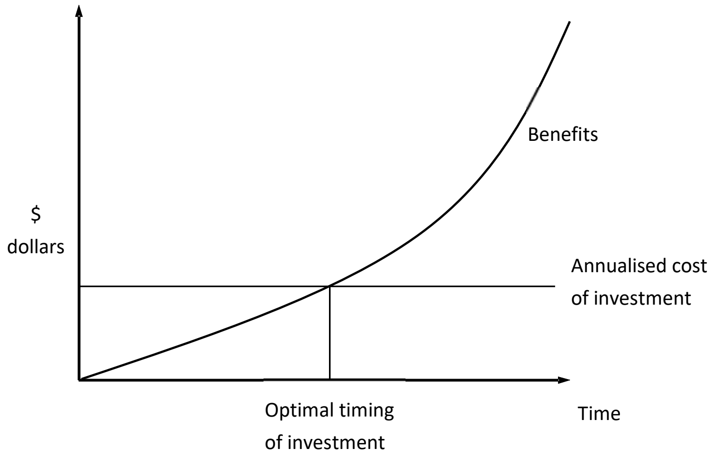


Figure 12 – CECV and Carbon Emissions Investment Decisions

Figure 12 shows demonstrates the optimum timing concept for network investment, where the benefits increase over time as the minimum demand, CECV and carbon emissions costs increase to a point at which the annualised cost of investment is lower than the benefits of alleviating curtailment. More information can be found on this concept in supporting document Cost Benefit Framework and Principles.

In responding to curtailment costs there are broadly two types of network investments that are modelled in our analysis – LV and HV network constraints.

4.8.1 LV Network Constraints

LV network constraints occur where the export increase on a distribution transformer that results in the transformer being the limiting piece of equipment in our network, resulting in excessive curtailment of customers DER. A weighted average cost of $100k has been applied in our modelling to relieve constraints of this type, which reflects the costs associated with the typical solutions to resolve these constraints:

- reconfiguring the low voltage (LV) network to transfer customer connections between distribution transformers.
- replacing an existing distribution transformer with a larger one that will not curtail customers, or at least curtail customers to a lesser extent.
- establishing a new distribution transformer that enables new capacity to be added to the network.

The process for assessing the hosting capacity for distribution transformer constraints is more straightforward than that for distribution feeders. For thermal constraints, we have simply used the nameplate capacity of each of our 40,000 distribution transformers in our network and compared this against the minimum demand forecasts outlined in Section 5. The cost to resolve a distribution transformer constraint has been estimated at $100k, which is a weighted average of our typical mix of resolutions, including load transfers and switching, replacement of a transformer with a larger unit, or the addition of a new transformer and associated LV network where the transformer capacity can't be increased.

For voltage constraints, we have utilised the voltage constraint results from the distribution feeder analysis. To do this, we have undertaken the following steps on a feeder-by-feeder basis. We first determine the level of export at which a feeder has a voltage constraint.

1. Determine the level of export at which a feeder has a voltage constraint.

2. Utilising the same method for distribution transformer minimum demand forecasts as in Section 5, split the export demand at which the feeder has voltage constraints to each distribution transformer. For example, if a demand of -2MW causes voltages higher than statutory limits, this demand gets split amongst all the distribution transformers according to the inverter capacity at each transformer. This becomes the hosting capacity of each distribution transformer on the feeder.

3. This hosting capacity is then compared to the minimum demand forecast to determine whether there is a constraint on the network. The cost of resolving voltage constraints on the LV network has been estimated as $50k, which is a weighted average of changing tap settings on an LV transformer to the addition of an LV circuit or transformer where the extents of voltage control have been reached.

This cost to resolve and timing of the constraint for both thermal and voltage limits are then captured to determine the investments required to provide a certain level of export from DER. It should be.

4.8.2 HV Network Constraints

HV network constraints occur where the export increase on our distribution feeders, resulting in excessive curtailment. These typically fall into either a downstream feeder constraint, where a branch of our feeder is the constraining piece of equipment resulting in curtailment, or where the backbone of the feeder in the constraining element of the network. The costs below have been utilised in our modelling of the costs associated with relieving these constraints:

- Downstream feeder constraint – this has been estimated at $500k to resolve.
- Backbone feeder constraint – this has been estimated at $1m to resolve.

The process we have undertaken to determine the hosting capacity of our network is outlined below. These steps are undertaken utilising automated load-flows, and so provides a set of results for all feeders in our network.

1. The initial minimum demand on each feeder is allocated to each distribution transformer across the feeder to determine the initial power flow and voltage profile on the feeder.

2. The overall minimum demand is reduced by 0.5MW until a constraint on the feeder arises. The three general constraints are:

    a. **Voltage** – a voltage rise outside of statutory limits is reached due to excessive export on the network. We have set a threshold for voltage constraint as reaching 1.02pu at any point on a distribution feeder, which is the point at which LV feeders begin to have voltages higher than statutory limits. Where a voltage limit is identified on a distribution feeder, an average cost of $300k is assumed to resolve this through the establishment of a voltage regulator.

    b. **Downstream feeder** – a portion of the feeder not on the initial backbone of the feeder has reached its thermal limit due to export. It would generally be considered that this is due to a low-capacity section of a feeder has reached its limit and may be resolved through reconductoring or load transfer. This is estimated at a cost of $500k / constraint.

c. **Upstream feeder** – a portion of the initial backbone of the feeder has reached its limit. This is likely to mean that a new distribution feeder would be required to resolve the constraint. This is estimated at a cost of $1m / constraint.

3. The minimum demand at which the constraint is revealed is captured, which is then compared to the minimum demand forecast on the feeder to determine whether a constraint exists on the feeder.

The cost to resolve and timing of the constraint is captured to determine the investments required to provide a certain level of export from DER.

4.9 Reverse flow protection

We have a requirement to provide protection to isolate any faults on our network. Networks have traditionally operated in a single direction, and some of our protection systems were designed in this manner. As networks begin to operate in reverse, some of our protection systems will require upgrading to ensure our ongoing compliance with the National Electricity Rules, as well as providing a safe network for our customers.

We have identified several substations that are unlikely to be able to clear all faults on the network under credible network conditions, and this initiative rectifies this situation. These investments are covered under a separate business case, available on request.

Part 3 - Forecasting Customers DER Integration Requirements

5 FORECASTING DER INTEGRATION REQUIREMENTS

The key driver for integrating DER for our customers is the resultant minimum demand, or negative peak demand, that results from the continued uptake of embedded generation from our customers. Chapter 4 of our Regulatory Proposal, with supporting document Blunomy Distributed Energy Resource Forecast outline the process we undertake to forecast the uptake of DER and the resultant impact on minimum demand. Our Strategic Forecasting Annual Report containing our detailed DER forecasts is published on our website each year.

These forecasts are out to 2032 and go down to a distribution feeder level. In addition to these forecasts, for the purposes of forecasting export service requirements and consequential hosting capacity needs, we require two extra steps, outlined in the following sections.

5.1 Estimated customer export levels

For non-industrial customers, export is only considered to be from PV systems. It is recognised there are other mechanisms for customer export such as from BESS and EV to grid, however these are assumed to be negligible in the forecast period.

Future export is estimated based on historical proportions of actual export energy to recorded PV inverter capacity in the DER register (the export to capacity ratio) and applied to the forecasted PV capacity. The export to capacity ratio is then calculated each month for business and residential customer groups. On average business customers export 43% of their rated capacity and residential customers export 76%. We have utilised these ratios to assess the export requirements from our customers, and the level of curtailment resulting from any hosting capacity constraints in our network.

5.2 Distribution transformer minimum demand forecasts

The distribution transformer minimum demand forecasts are utilised to determine an export forecast at each distribution transformer in our network. Our DER Register is a database that stores the inverter capacity for each customer that has connected solar to our network, and tracks which of our distribution transformers these are connected to. We also have data for the number of customers connected to each distribution transformer and the distribution feeder that each transformer is connected to.

To generate a minimum demand forecast for each distribution transformer, we take the following steps:

1. **Determine the theoretical existing feeder minimum demand (CMD).** This calculation utilises the total inverter capacity on a feeder by using the inverter capacity on all distribution transformers supplied by the feeder. This uses an average output of around 73% of rated inverter capacity. This determines the theoretical minimum demand on a feeder if only customers with export were connected.

2. **Determine the load demand of those customers that haven't connected a DER (AD)**. This is done by determining the volume of customers without DER and determining the average load that each customer has for the forecast to reconcile.

3. **Adjust the minimum demand (AMD)** – this creates the starting point for each distribution transformer's minimum demand, based on each transformer's contribution to the feeder's minimum demand**.** That is, the estimated minimum demand of each transformer is proportionate to its level of export penetration. This means that a distribution transformer's estimate starting minimum demand is directly proportionate to the level of DER that is

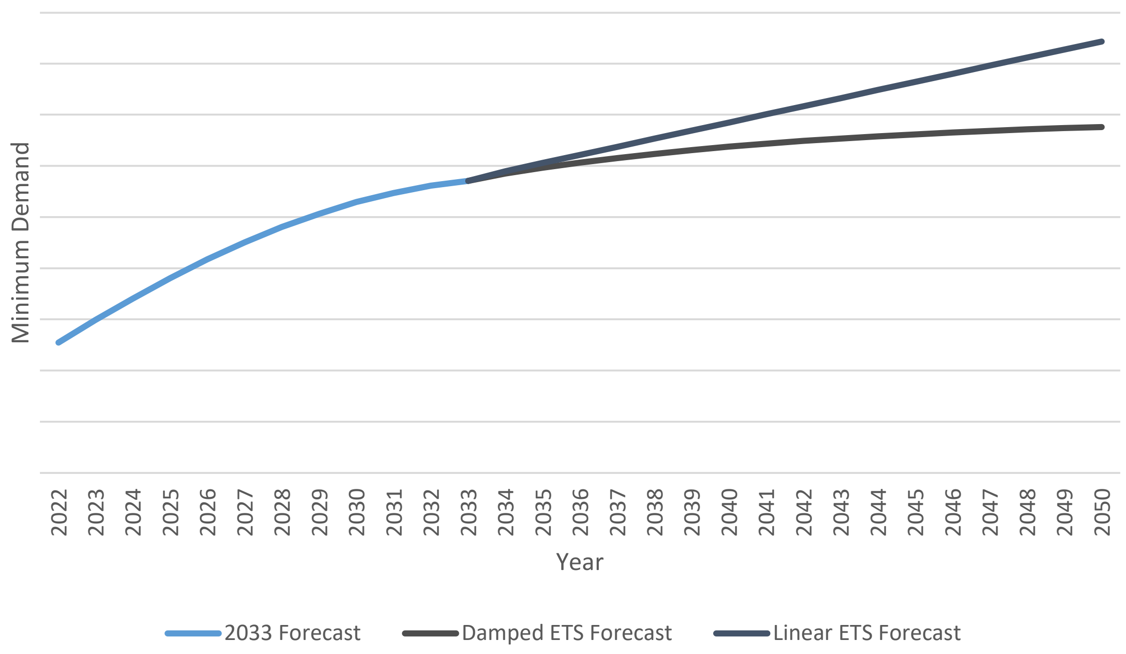
connected to it, rather than on other common metrics such as transformer size, or total number of customers.

4. **Grow minimum demand to determine future minimum demand (FMD)** – the growth in minimum demand for distribution transformers is then done based on the proportion of customers that don't currently have DER. That is, the minimum demand growth that is attributed to each distribution transformer from the distribution feeder is proportionate to the number of customers without DER. This avoids applying a uniform growth across all transformers, but rather attributing minimum demand growth to where customers are most likely to install DER and cause the change we are forecasting.

5.3 Forecasts to 2050

As discussed, our detailed forecasts only extend to 2032. In modelling our investment needs for the 2025-2030 period, we have extended our forecasts out to 2050 to ensure that our strategy gives benefits to both our existing and future customers. We have utilised a damped exponential smoothing (ETS) model to be generate a minimum demand forecast for each distribution feeder which utilises the last three years forecasts to project forward, utilising either a damped or linear forecast. An example of this approach is shown in Figure 13.

Figure 13 – Minimum Demand Forecasting Example



As the example in Figure 13 demonstrates, the linear and damped ETS forecasts produce different minimum demand forecasts out into the future. For the purposes of our modelling, we have taken the approach to utilise the damped forecasts as a conservative view of our customers' requirements beyond the 2032 forecasts for both distribution feeders and distribution transformers.

While DER penetration almost doubles in the coming period, we expect that beyond 2035 there will be a saturation effect where the volume of export required from our network flattens out. To test the sensitivity of our results, we utilise the Linear ETS model to understand the value of our options for higher penetration into the future.

Part 4 – DER Integration Cost Benefit Analysis

6 DER INTEGRATION BUSINESS CASE

To determine the initiatives that we have included in our 2025-2030 Regulatory Proposal outlined in Section 2, we have undertaken a cost benefit analysis with the range of interventions we identified in Section 2.2.

For our analysis, we have assumed that Inverter Compliance, Tariff Design for peak demand behavioural change and our Demand Management Plan initiatives have been implemented. This assumption has formed the basis for our Counterfactual analysis. That is, we have assumed that we will implement these things, and our cost benefit analysis only needs to test the extra options above these three. The key assumptions that we have utilised from these inputs are:

- **Tariff design**: through our design of time-of-use demand tariffs in consultation with our Voice of the Customer panels, we have forecast an improvement in the minimum demand of 0.1kW / customer. This improvement has been modelled as part of the counterfactual and the options we have considered.
- **Demand management**: through use of our “solar soak” hot water and other load control capability, we have forecast an improvement of 0.36kW / customer with controlled load in our minimum demand. This improvement has been modelled as part of the counterfactual and the options we have considered.
- **Network voltage**: overvoltage is not a significant concern flowing from the connection of new embedded generation. The current inverter standards mean that export output is reduced to control network voltages. Although we no longer foresee overvoltage as a concern, we still consider this reduction in output as curtailment, and value the benefits of alleviating this curtailment through use of the CECV and carbon emissions reduction.

In assessing the options available to us to integrate customer export services, we have considered alternative options to implementing dynamic connections and the level of grid visibility for our network in the following sections, which outlines the costs and benefits of the various options.

In undertaking the cost benefit analysis, the value streams have all been calculated as costs to that option. For instance, in considering curtailment of export we have calculated the CECV implications as a cost to this option. In calculating the NPV in comparison to the counterfactual, we have calculated the costs associated with each option, and then the cost savings of that option in comparison to the counterfactual has become the benefit.

6.1 Summary

<table>
<tr><th>Title</th><th>DER Integration Strategy Busines Case</th></tr>
<tr><td>DNSP</td><td>Energex</td></tr>
<tr><td>Expenditure category</td><td>☐ Replacement ☐ Augmentation ☐ Connections ☐ Tools and Equipment
☐ ICT ☐ Property ☐ Fleet ☒ DER Integration</td></tr>
<tr><td>Identified need
(select all applicable)</td><td>☐ Legislation ☐ Regulatory compliance
☐ Reliability ☒ CECV ☐ Safety ☐ Environment ☒ Financial
☐ Other

This case addresses the need to integration customer DER onto our network. The benefits that will flow from this include:
CECV – the economically efficient level of export enablement and curtailment of customer resources.
Financial – ensuring an optimal level of export will enable us to invest in network increases in an efficient way.</td></tr>
<tr><td>Summary of preferred option</td><td>We have considered 3 main options, and have incorporated components of 2 of these:
Option 1 – provide customers with the choice of an export charge and invest in network capacity upgrades accordingly.
Option 2c – continue implementing our Dynamic Connections framework and investing in Grid Visibility and out DERMS systems to enable customers to connect under a dynamic operating envelope.</td></tr>
<tr><td>Expenditure</td><td><table><tr><th>$m, direct 2022-23</th><th>2025-26</th><th>2026-27</th><th>2027-28</th><th>2028-29</th><th>2029-30</th><th>2025-30</th></tr><tr><td>Capex</td><td>5.9</td><td>8.3</td><td>7.0</td><td>4.0</td><td>4.5</td><td>29.6</td></tr></table></td></tr>
<tr><td>Benefits</td><td>This investment has been assessed over a 15-year horizon, with significant economic benefits flowing to our customers.</td></tr>
<tr><td>Consumer engagement</td><td>We have discussed DER integration at two customer focus groups, with customers generally supporting the integration of DER into our network and the level of investment that we have proposed.</td></tr>
</table>

6.2 Counterfactual

The counterfactual we have considered is to invest in upgrading LV network capacity to enable DER to be connected to our network. We have not included HV feeder upgrades in this analysis as the impacts at this level are not currently considered to be major costs associated with integrating DER. Rather, the major costs and benefits fall to the LV network in transformer upgrades and LV network reconfigurations.

There are several assumptions in constructing the counterfactual case:

- **Dynamic Connections** – the counterfactual assumes that we won't have dynamic connections for customers connecting DER. While we can offer these, it is important that we consider that these don't exist for the counterfactual as this has been the business-as-usual strategy for some time, and that there is proposed expenditure in the next regulatory period to continue to enable these. As such, we have assumed that the prevailing 5kW export limit continues into the next period.

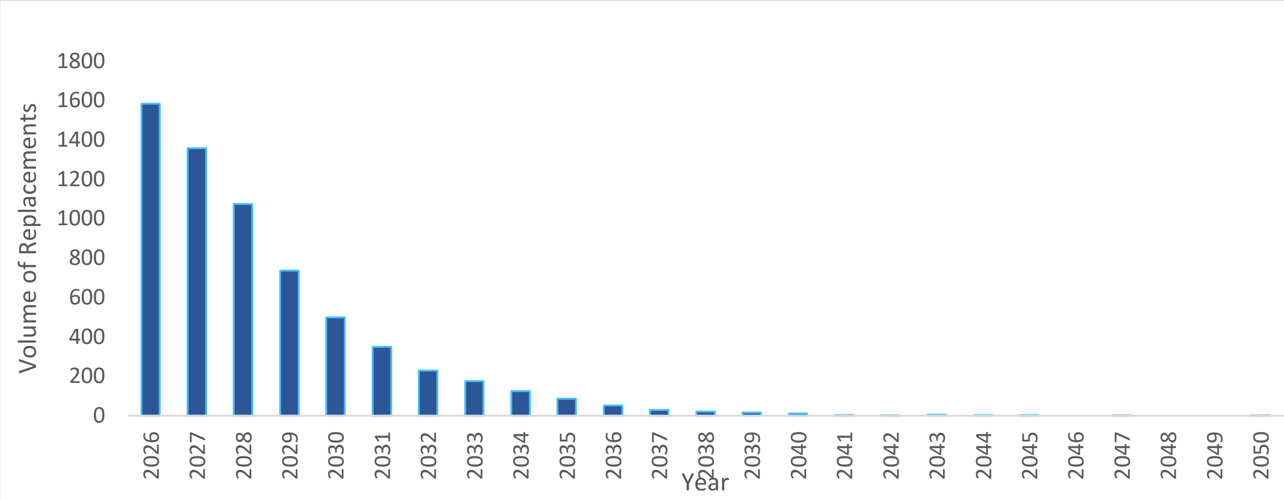
- **Capacity upgrade timing** – this has been set to a level where the inverter capacity of connected customers exceeds the rating of our distribution transformers and feeders. This suggests that customers are exporting 100% of their solar capacity. While we typically expect between 70% and 80%, without live data of the levels of export on our network, we assume this so we can maintain safe operation of our network by risking overloading of transformers and feeders. For clarity, one of the options we consider includes a strategy of providing visibility of a transformer or feeders actual export as a cost, and then investing once the export reaches the capacity of our assets. We want to demonstrate the value of this proposition for our customers, so have considered the counterfactual absent of this strategy.

- **Inverter compliance** – it has been assumed that any increase in export capacity would come with inverters that are compliant with current standards under the counterfactual.

- **Period of assessment** – to ensure that our strategy benefits customers in long term, we have assessed our DER integration strategy from 2025-2050. While we acknowledge that the future is uncertain, we think it is in the best interest of customers for our modelling to go out this far to ensure our options are robust to both immediate and long-term network requirements.

Figure 14 outlines the number of distribuiton transformer upgrades that would be required under the counterfactual.

Figure 14 – Counterfactual Distribution Transformer Capacity Upgrades



As Table 5 demonstrates, there will be a significant investment required to maintain network capacity to enable export services. Table 5 shows the NPV costs associated with the counterfactual.

Table 5 – NPV for Counterfactual

Value Stream	Net Present Value ($m)
Network capacity increase	651.02
CECV	0.00
Carbon Emissions Value	0.00
Net Present Cost	**651.02**

As Table 5 shows, there is a significant present value cost in an approach of increasing network capacity to meet the total export capacity of our customers. This cost will form the basis of the benefits of our proposed options in reducing our need to invest in the network upgrades.

6.3 Option 1 - Tariff intervention through Two-Way Tariffs

This option involves a tariff only strategy, with two-way tariffs utilised to send a price signal to all customers with export, with the resultant minimum demand being higher than would otherwise be the case. We will still provide a BEL of 1.5kW. However, we will charge all exports above the BEL.

In assessing this option, we have modelled that:

- We will have an impact on the export market, assuming a reduction of a 0.1kW / customer with export reduction in their overall purchase. This is on the basis that with a two-way tariff, customers would choose smaller systems. We have modelled this impact with a CECV and Carbon emissions impact, effectively that the overall market will have less export than would otherwise have been the case.

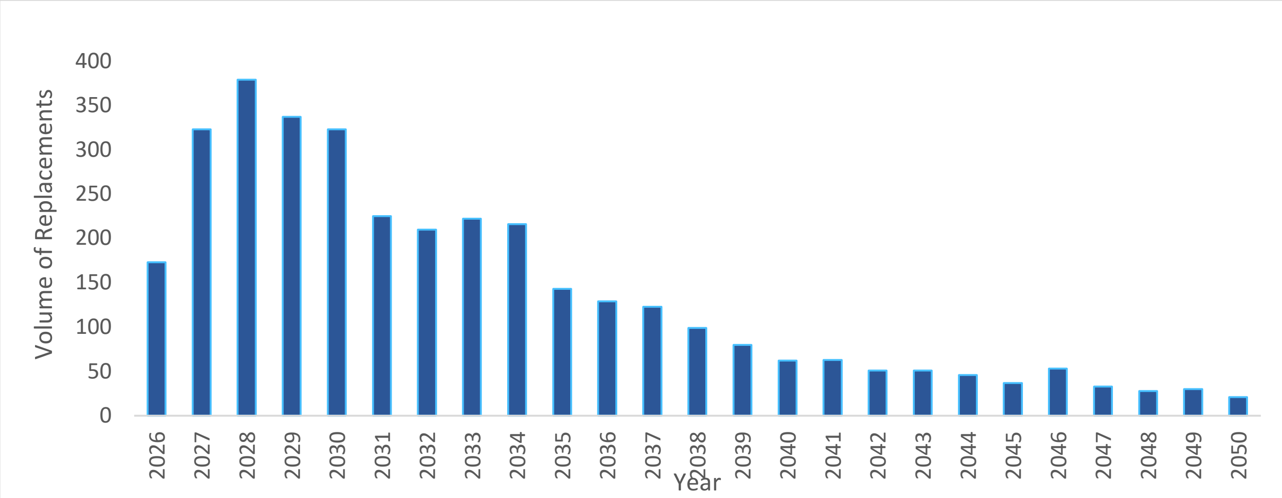
- There will be an impact on minimum demand of 2kW / customer for those with two-way tariffs. This assumes that customers with export will use a significant amount of energy through the middle of the day to avoid exporting onto the network because of the charge. This is a significant behavioural shift, and we expect that the improvement in minimum demand from two-way tariffs are likely to be substantially less than this, meaning this is a conservative approach.

- While charging customers for export will have an impact on reducing demand for export services, we are still forecasting the need to upgrade network capacity to allow for these customers to export energy in line with their anticipated behaviour in response to tariff incentives. As such, we have modelled a level of capital cost requirements to increase network capacity to provide these customers the choice of exporting to the network despite incentives not to.

In modelling the benefits of this intervention, we have compared the cashflow of capital costs associated with this option against the original cashflows associated with the “Counterfactual”. While we haven’t factored in a cost associated with enabling an export tariff, we have calculated the costs associated with upgrading the network that will result from customers exporting onto our network. The practical outcome of a tariff only solution is that there will be a reduction in minimum demand issues on our network, however we still expect that areas on our network will require increased capacity where customers export more than the capacity of their local network. This will manifest as distribution transformer upgrades to cater for these export services.

The benefits of this option are a reduction in network investment in transformer upgrades due to the substantial improvement in minimum demand that we have modelled, offset by the increased CECV and Carbon emissions from a reduced level of export capacity from customers. Figure 15 outlines the number of distribution transformer upgrades that would be required under this option.

Figure 15 – Option 1 Distribution Transformer Capacity Upgrades



As Figure 15 outlines, there is a substantial decrease in transformer upgrades because of the tariff intervention. Table 6 outlines the net benefits of this option.

Table 6 – Option 1 Net Benefits

Value Stream	Counterfactual NPV ($m)	Option 1 – Two-Way Tariffs
Network capacity increase	651.02	277.16
CECV	0.00	25.26
Carbon Emissions Value	0.00	15.99
Net Present Cost	**651.02**	**318.41**
	Net Present Value [3]	**332.61**

This option requires export prices to do the heavy lifting to reduce expenditure on the network. Tariff interventions are difficult to target, and we have modelled this impact across our entire customer base. Unlike DOEs, which only reduce export for those customers connected in constrained networks, tariff intervention impacts all customers, whether in constrained networks or not. This comes at the expense of reduced overall export as we anticipate that two-way tariffs will have the impact of reducing overall investment in DER from our customers.

Table 7 – Cost of Option 1 for 2025-2030 regulatory control period

Expenditure ($m, 2023)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
LV Network Upgrades	17.3	32.8	38.1	33.8	32.8	**154.8**

[3] This is the difference between Net Present Costs of Option 1 and the Counterfactual

6.4 Option 2 – Dynamic connections and DOEs

We have already begun implementation of dynamic connections; however, it is still important to assess the benefits to all customers of having the ability to control export for those customers that allow us to do so. We have assessed three levels of dynamic connections, each of which requires different levels of data and network visibility to implement more accurate DOEs.

Table 8 summarises the investments required to enable each of 2a, 2b and 2c.

Table 8 – Summary of Investments in Option 2a, 2b and 2c

Option	LVDERMS	Telemetry Hub	Transformer Monitoring	LV Service Line Monitoring
2a	Yes	No	No	No
2b	Yes	Yes	Yes	No
2c	Yes	Yes	Yes	Yes

As Table 8 shows, the major difference between each of these options is the level of monitoring that we utilised in setting our dynamic operating envelopes, with option 2a requiring none, and option 2c requiring a high level of visibility.

6.4.1 Option 2a - Basic DOEs with no grid visibility

The key features of this version of the option are that no network monitoring and visibility devices are installed to decrease the level of curtailment for our DOE. In effect, this means that we need to be more conservative in our curtailment of customers, as we can't accurately predict the level of export on our network. Not doing this would result in a higher likelihood of plant damage through excessive overloading of our transformer network. The algorithm we will utilise in curtailing customer export at a distribution transformer level where there is no monitoring is:

- Load is zero for customers without DER.
- There is no self-consumption for customers with DER (export is up to the full export capacity)
- Voltages are within limits.
- Installed DER capacity is exporting at:
  - 100% capacity from 10:00 to 14:00
  - 80% capacity from 08"00 to 10:00 and 14:00 to 16:00
- 0% capacity at all other times

The three main costs associated with this option that we have factored into our modelling are:

- Continued implementation of our DOE framework, including the ongoing costs of our Distribution Energy Resources Management System (DERMS). Without the need for grid visibility, our telemetry hub does not require upgrading. In NPV terms out to 2050, we have assessed this cost as $5.9m.

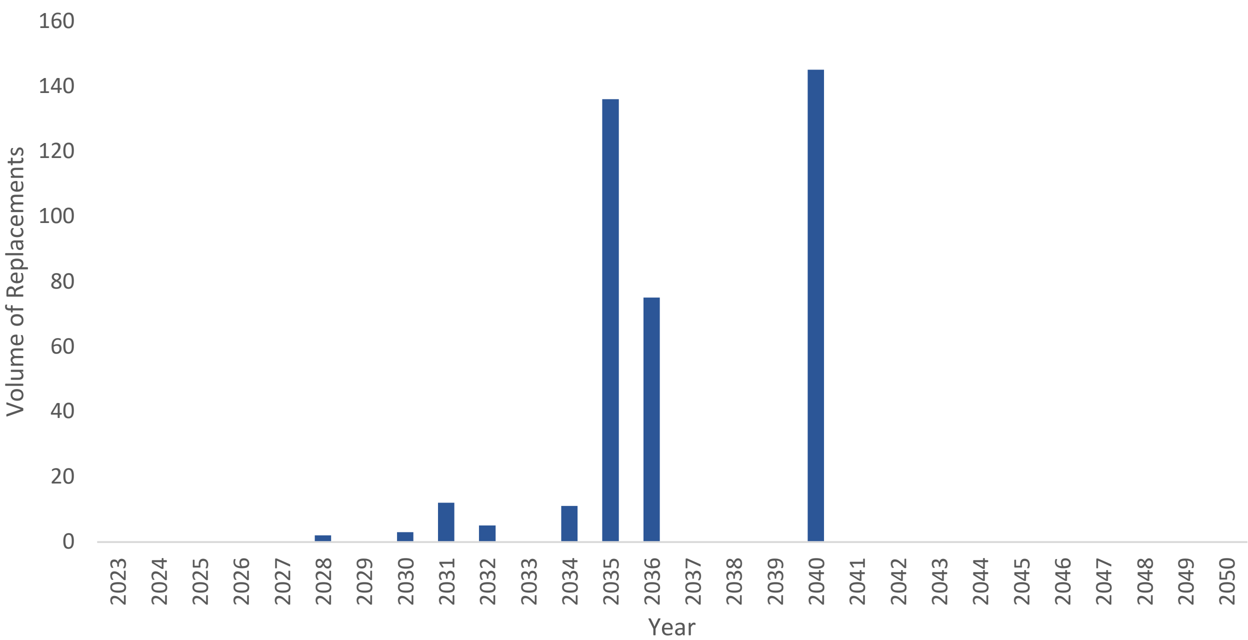
- the CECV from the curtailment of customers from the implementation of a DoE

- carbon emissions from the curtailment of renewable DER, which are higher than would have been the case without curtailment.

These have been modelled utilising the DoE curtailment algorithm detailed above, in combination with the cost benefit analysis method outlined in Part 2. In essence, this results in us curtailing customer export to the point at which the CECV plus carbon emissions costs exceed the cost of upgrading our network capacity to alleviate the constraints.

In modelling the benefits of this intervention, we have compared the cashflow of capital costs associated with this option against the original cashflows associated with the "Counterfactual". The benefits of this option are entirely in the "Financial" value stream, with a capital deferral occurring through the deferral of network capacity upgrades by curtailing customer export until the CECV plus carbon emissions exceed this cost of upgrade. Figure 16 outlines the number of distribution transformer upgrades that would be required under this option.

Figure 16 – Basic DOE Distribution Transformer Capacity Upgrades



As Figure 16 outlines, there is a substantial decrease in distribution transformer upgrades because of implementing the Basic DoE. The spike in replacement volumes in 2035 and 2040 are due to substantial increases in the CECV in those years representing the right time to invest in network capacity to offset lost export.

Table 9 outlines the net benefits of this option.

Table 9 – Basic DOE Net Benefits

Value Stream	Counterfactual NPV ($m)	Basic DOE ($m)
Network capacity increase	651.02	115.35
CECV	0.00	76.49
Carbon Emissions Value	0.00	30.46
Dynamic Connections Implementation	0.00	5.87
Net Present Cost	**651.02**	**228.17**
	Net Present Value[4]	**422.85**

As Table 9 shows, there is a net benefit for customers of $422.85m to implement this option. The benefits as against the counterfactual are entirely in the network investment area, with deferrals of network capacity upgrades a significant saving. This comes at the expense of a high level of curtailment of customer resources, and in effect a reasonably high "waste" of energy given the conservative approach we must take to setting the level of curtailment. Because of this heavy curtailment, our forecast expenditure on increased network capacity is higher than our more advanced DOE options, with the cost associated with extra curtailment being offset by having to increase network capability. Table 10 outlines the costs associated with Basic DOEs in the 2025-2030 regulatory control period.

Table 10 – Capital Cost of Basic DOE in 2025-2030 Period

Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
LVDERMS Implementation	1.23	0.25				**1.49**
LV Network Upgrades	0	0.50	0	0	0.70	**1.20**

6.4.2 Option 2b - DOEs and basic grid visibility

The key features of this option are that we establish distribution transformer monitoring at transformers that have customer connected inverter capacity higher than the rating of the transformer. This monitoring will enable us to match customer export more effectively to the rating of our distribution transformer, with our estimates being that we will be able to utilise around 80% of the transformer capacity. Because we still won't have significant visibility of our network, we will still have to be conservative in our approach to avoid overloading our transformer.

The four main costs associated with this option that we have factored into our modelling are:

- Continued implementation of our DOE framework, including the ongoing costs of our Distribution Energy Resources Management System (DERMS). With grid visibility requirements, this option includes the upgrade and ongoing increased costs for the telemetry hub. This has an NPV cost of $18.90m.
- Installing transformer monitors on constrained transformers with higher inverter capacity than the transformer rating. It should be noted that transformer monitors have other benefit streams and a separate business case. This has an NPV cost of $17.32m.

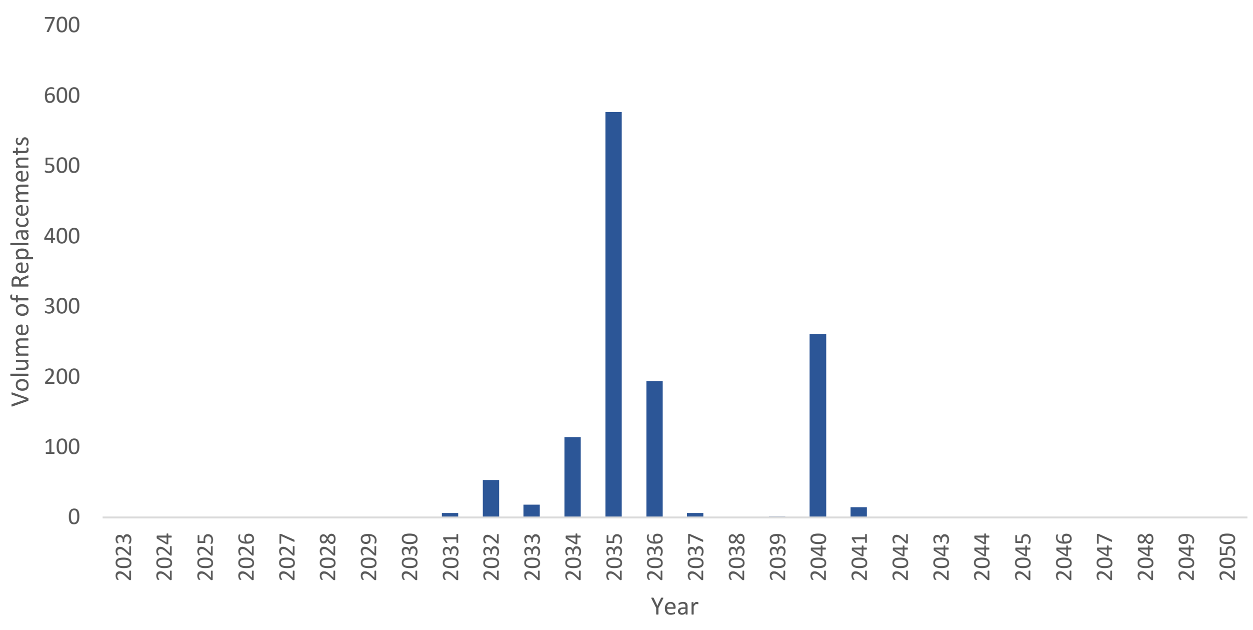
[4] This is the difference between Net Present Costs of Option 2a and the Counterfactual

- CECV from the curtailment of customers from the implementation of a DEE. The level of curtailment will generally be lower for customers than for our Basic DOE option.
- Carbon emissions from the curtailment of renewable DER, which are higher than would have been the case without curtailment.

These have been modelled utilising a distribution transformer capacity limit of 80% of the nameplate capacity, to ensure that we don't overload our transformers because of having limited visibility. This is done in combination with the cost benefit analysis method outlined in 3.3 to determine the level of curtailment prior to network investment is required. In essence, this results in us curtailing customer export to the point at which the CECV plus carbon emissions costs exceed the cost of upgrading our network capacity to alleviate the constraints.

In modelling the benefits of this intervention, we have compared the cashflow of capital costs associated with this option against the original cashflows associated with the "Counterfactual". The benefits of this option are entirely in the "Financial" value stream, with a capital deferral occurring through the deferral of network capacity upgrades by curtailing customer export until the CECV plus carbon emissions exceed this cost of upgrade. Figure 17 outlines the number of distribution transformer upgrades that would be required under this option.

Figure 17 – DOE and Basic Grid Visibility Distribution Transformer Capacity Upgrades



As Figure 17 outlines, there is a substantial decrease in distribution transformer upgrades because of implementing this level of grid visibility and our dynamic connections framework. The spike in replacement volumes in 2035 and 2040 are due to substantial increases in the CECV in those years representing the right time to invest in network capacity to offset lost export. Table 11 outlines the net benefits of this option.

Table 11 – DOE and Basic Grid Visibility Net Benefits

Value Stream	Counterfactual NPV ($m)	DOE and Basic Visibility ($m)
Network capacity increase	651.02	81.84
CECV	0.00	55.43
Carbon Emissions Value	0.00	26.03
Network Monitoring	0.00	17.32
Dynamic Connections Implementation	0.00	18.90
Net Present Cost	**651.02**	199.51
	Net Present Value[5]	**451.51**

As shown in Table 11, this option has a net benefit for customers of $451.51m as compared to the counterfactual. This is around $30m higher than for Option 2a, and also higher than Option 1 and 3.

The benefits as against the counterfactual are entirely in the network investment area, with deferrals of network capacity upgrades a significant saving. This comes at the expense of a moderate level of curtailment of customer resources, and in effect some "waste" of resources given the conservative approach we take to setting the level of curtailment. The CECV and Carbon values are higher than for the Basic DoE. This is because the heavy curtailment under Option 2a in the earlier years results in earlier investment in increasing the network capacity, which means that overall curtailment is decrease in favour of higher earlier curtailment. Table 12 outlines the costs associated with DOEs with Basic Grid Visibility in the 2025-2030 regulatory control period.

Table 12 – Cost of DOE with Basic Grid Visibility in 2025-2030 Period

Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
LVDERMS Implementation	1.23	0.25	-	-	-	**1.49**
Telemetry Hub Upgrade	0.93	0.93	-	-	-	**1.86**
Network Monitoring[6]	2.28	2.28	2.28	2.28	2.28	**11.40**
LV Network Upgrades	-	0.50	-	-	0.50	**1.00**

6.4.3 Option 2c - DOEs and high grid visibility

The key features of this version of the option are that we have a high level of grid visibility to enable us to provide DoE's that effectively match our transformer capacity. This involves a combination of transformer monitors, acquiring live smart meter data and establishing an LV monitoring capability for those areas that don't have high smart meter penetration. We expect that we need around 25% of live power quality data across our network, which, in combination with our Distribution System State Estimation (DSSE) system, will enable us to provide close to full export capability at our transformers. Our modelling has assumed that we are able to achieve 100% export capability of our transformers from being able to actively monitor and estimate system outputs.

[5] This is the difference between Net Present Costs of Option 2b and the Counterfactual
[6] This expenditure has been forecast as flat across the period for deliverability.

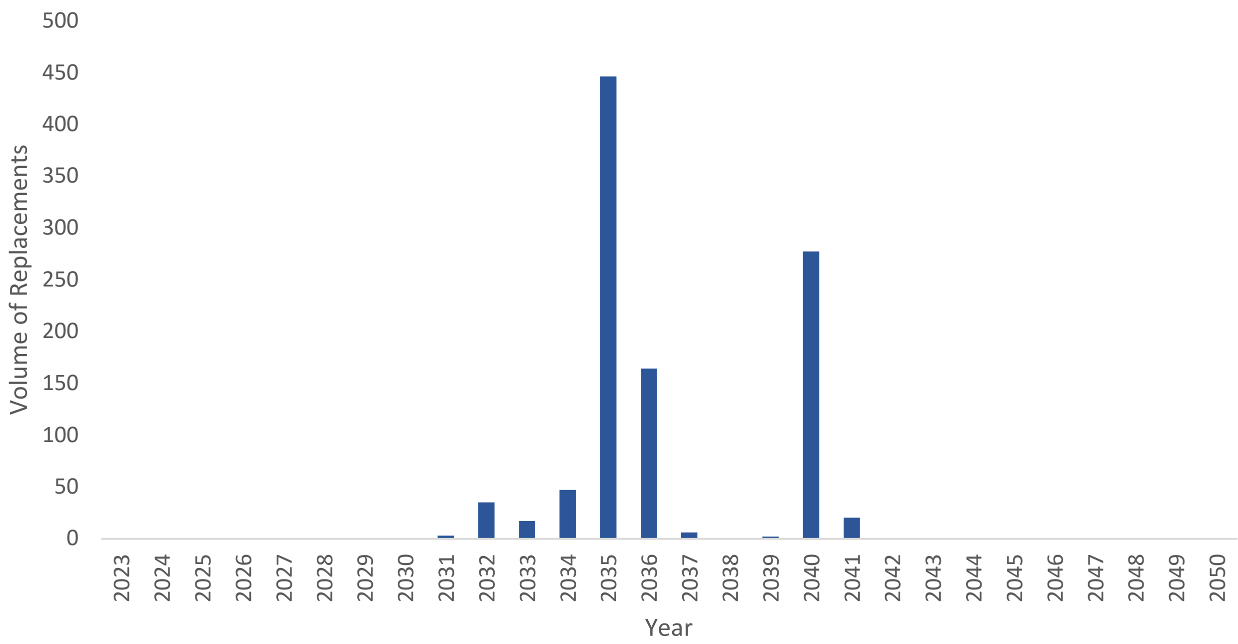
The five main costs associated with this option that we have factored into our modelling are:

- Continued implementation of our DOE framework, including the ongoing costs of our Distribution Energy Resources Management System (DERMS). As for Option 2b, this includes the upgrade of the telemetry hub. In NPV terms, the costs of DERMS out to 2050 is $18.90m.
- Installing transformer monitors on constrained transformers with higher inverter capacity than the transformer rating. It should be noted that transformer monitors other benefit streams and has a separate business case. The benefits that are attributable to these devices will be captured in that business case. This has an NPV cost of $17.32m.
- Acquiring smart meter data and establishing LV monitors to be able to monitor 25% of power quality metrics at the connection points of our network. It should be noted that these elements have other benefits streams and have a separate business case. The benefits that are attributable to these devices will be capture in that business case as well.
- CECV from the curtailment of customers from the implementation of a DOE. The level of curtailment will generally be lower for customers than for our Basic DOE
- Carbon emissions from the curtailment of renewable DER, which are higher than would have been the case without curtailment.

These have been modelled utilising a distribution transformer capacity limit of 100% of the nameplate capacity given the level of visibility across our network. This is done in combination with the cost benefit analysis method outlined in Part 2 to determine the level of curtailment prior to network investment is required. In essence, this results in us curtailing customer export to the point at which the CECV plus carbon emissions costs exceed the cost of upgrading our network capacity to alleviate the constraints.

In modelling the benefits of this intervention, we have compared the cashflow of capital costs associated with this option against the original cashflows associated with the “Counterfactual”. The benefits of this option are entirely in the “Financial” value stream, with a capital deferral occurring through the deferral of network capacity upgrades by curtailing customer export until the CECV plus carbon emissions exceed this cost of upgrade. Figure 18 outlines the number of distribution transformer upgrades that would be required under this option.

Figure 18 – Option 2c Distribution Transformer Capacity Upgrades



As Figure 18 outlines, there is a substantial decrease in distribution transformer upgrades because of implementing this level of grid visibility and our dynamic connections framework. The spike in replacement volumes in 2035 and 2040 are due to substantial increases in the CECV in those years representing the right time to invest in network capacity to offset lost export. Table 13 the net benefits of this option.

Table 13 – DOE and High Grid Visibility Net Benefits

Value Stream	Counterfactual NPV ($m)	DOE and High Visibility ($m)
Network capacity increase	651.02	77.39
CECV	0.00	47.94
Carbon Emissions Value	0.00	23.13
Network Monitoring	0.00	17.32
Dynamic Connections Implementation	0.00	18.90
Net Present Cost	**651.02**	**184.68**
	Net Present Value[7]	**466.34**

As Table 13 outlines, there is a net benefit for customers of $466.34m, which is higher than Option 1, as well as 2a and 2b. It should be noted that this option requires a level of grid visibility that will be achieved using smart meter data and our LV monitor programs. There are significant other benefits to these programs which have been outlined in our attachment - Smart Meter Data Acquisition Business Case. The additional benefits from this cost benefit analysis have been added to the value streams in this business case. As such, the costs associated with smart meter data acquisition have not been included in this business case.

[7] This is the difference between Net Present Cost of Option 1 and the Counterfactual

The benefits as against the counterfactual are entirely in the network investment area, with deferrals of network capacity upgrades a significant saving. This comes at the expense of some level of curtailment of customer resources, however with greater network visibility this is optimised against network investment but involves having a much higher level of network monitoring available, which comes at a cost. Table 14 outlines the costs associated with DOEs with High Grid Visibility in the 2025-2030 regulatory control period.

Table 14 – Cost of DOE with High Grid Visibility in 2025-2030 Period

Expenditure ($m, 2023)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
LVDERMS Implementation	1.23	0.25	-	-	-	**1.49**
Telemetry Hub Upgrade	0.93	0.93	-	-	-	**1.86**
Network Monitoring[8]	2.28	2.28	2.28	2.28	2.28	**11.40**
LV Network Upgrades	-	0.50	-	-	0.50	**1.00**

6.4.4 Summary of Option 2 Costs and Benefits

Table 15 shows the NPV for each of the DOE options under this option.

Table 15 – Summary of NPV for DOE Options

Option	Net Benefits for Customers
Basic DOE (2a)	**422.85**
DOE with Basic Grid Visibility (2b)	**451.51**
DOE with High Grid Visibility (2c)	**466.34**

As Table 15 shows, a DOE with High Grid Visibility offers the most value to our customers. This version of Option 2 allows for the highest level of export and lowest level of network investment. While it requires a high level of grid visibility, as our Smart Meter Data Acquisition business case outlines, there is significant customer safety and reliability value in obtaining this data for other purposes. Having already obtained the data, we are able to utilise it for the purposes of DER integration to maximise the benefits to customers.

It should also be noted that the cost benefit analysis shows that all three of the DOE options have a higher customer value than Option 1.

[8] This expenditure has been forecast as flat across the period for deliverability.

6.5 Option 3 – Monitor distribution transformers then upgrade

This option involves active monitoring of high penetration LV networks to defer investment in the network. As discussed earlier, the counterfactual sees us investing in the network at the point inverter capacity connected to an asset exceeds the rating of the asset, ensuring that we don't damage our plant by overloading it. This inherently assumes that 100% of a DER capacity is being exported, which is rarely the case. By installing monitoring capability in the form of a distribution transformer monitor, we can accurately assess the level of export on the network and defer the network upgrade relative to the counterfactual. The steps in this option are:

- **Assess inverter capacity** – monitor the level of connected DER to each distribution transformer in our network to determine when the inverter capacity on a transformer reaches 100% of the transformer's capacity.
- **Install DER monitoring device** – install a monitoring device on a transformer to actively monitor the true export demand on the asset.
- **Upgrade capacity** – being able to monitor the export required on a transformer will enable us to time the upgrade of the network to when export will be at the capacity of the transformer.

The costs associated with this option are the initial installation of a distribution transformer monitor at $5k / device at the point inverter capacity reaches transformer capacity, and $100k / transformer to upgrade the capacity of the network once actual export exceeds the transformer capacity.

In modelling the benefits of this intervention, we have compared the cashflow of capital costs associated with this option against the original cashflows associated with the Counterfactual. The benefits of this option are entirely in the "Financial" value stream, with a capital deferral occurring through establishing a transformer monitor prior to upgrading the network. Our modelling effectively assumes no curtailment of export under this option. Figure 19 outlines the number of distribution transformer upgrades that would be required under this option.

Figure 19 – Option 3 Distribution Transformer Capacity Upgrades

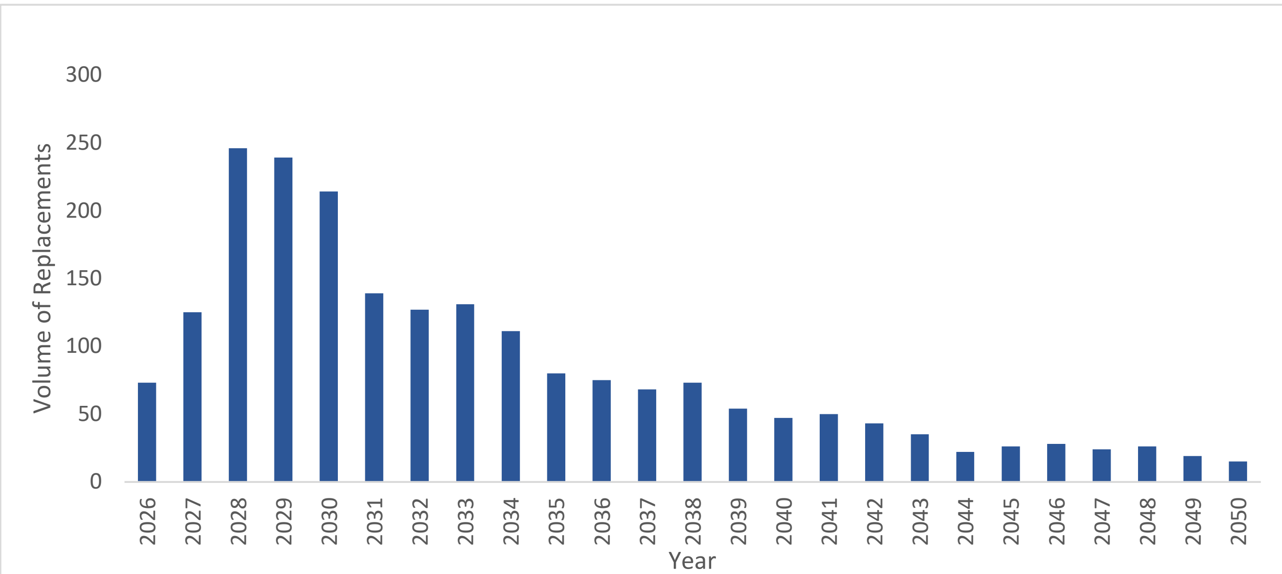


Table 16 outlines the present value cashflows associated with this option and compares these to the Counterfactual analysis.

Table 16 – Option 3 Net Benefits

Value Stream	Counterfactual NPV ($m)	Monitor then upgrade NPV ($m)
Network capacity increase and network monitoring	651.02	194.75
CECV	0.00	24.91
Carbon Emissions Value	0.00	15.92
Net Present Cost	**651.02**	**235.58**
	Net Present Value[9]	**415.44**

As Table 16 shows, there is a net benefit for customers of this option of $415m out to 2050. This option avoids the need for us to implement dynamic connections, rather we will be required to increase the capacity of our network in response to customers connecting their embedded generation. The clear advantage of this option is that we will be able to cater for all export onto our network that customers request, however this comes at the cost of increased network capacity and no improvement in asset utilisation. The overall cost of this option if we were to implement in full in this regulatory control period is shown in Table 17.

Table 17 – Cost of Option 3 in 2025-2030 Regulatory Control Period

Expenditure ($m, 2025)	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Network Monitoring[10]	2.28	2.28	2.28	2.28	2.28	**11.40**
LV Network Upgrades	7.30	12.50	24.60	23.90	21.40	**89.7**

6.6 Recommended Options

Tariff intervention, dynamic connections and network monitoring and capacity increases are options that all contribute to the integration of DER through enabling export through our network. They do this in different ways, and generally are options that would be considered as alternatives to each other. We would typically utilise the most positive NPV result, which is the dynamic connections option.

However, this does not offer choice to those customers who would like to export to their full capacity. To provide customer choice, we are proposing a hybrid solution that incorporates DOEs for those customers who choose to allow us to reduce their export at certain times of the day, while also providing a tariff only solution for those customers that would like to maximise their output.

To do this, our Tariff Structure Statement (TSS) has proposed that from 2026, new export customers will be faced with a two-way tariff or can opt-out should they choose to connect with a dynamic connection. From 2028, this will apply to existing export customers. The combination of these options has allowed us to provide customer choice in exporting onto the network, while also

[9] This is the difference between Net Present Costs of Option 3 and the Counterfactual
[10] This expenditure has been forecast as flat across the period for deliverability.

ensuring efficient capital expenditure in network capacity upgrades by fairly charging customers that cause network constraints.

As a result, our proposed network capacity upgrades for export services are a combination of the need under the DOE with High Grid Visibility (Option 2c) and Tariff Intervention through Two-Way Tariffs (Option 1).

Our TSS assumes a 50/50 uptake of either option from our customers. We acknowledge that there is limited information available to determine how customers will interact with our dynamic connections framework.

We have included around 10% of the expenditure associated with Option 1 in our expenditure forecast to ensure that we are able to respond to areas of the network that require upgrading in the next period cause by customers not on a DOE.

This is an estimate of the impact on the resultant network investment that customers without DOE, given that we will have significant numbers of customer that on a DOE that we would be able to reduce export on to ensure our assets are run within their ratings. We have also forecast a higher level of remediation requirements in the 2026-27 and 2027-28 years given this is just prior to us charging all customers for export.

Table 18 outlines the expenditure required for this hybrid solution and the options that we have incorporated into these investment streams.

Table 18 – Capital Expenditure from our Recommended Options

Expenditure ($m, 2025)	Associated Option	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Network Upgrades for non-DOE customers (Hosting Capacity)	10%[11] of Option 1	1.70	4.24	4.68	1.71	1.71	**14.03**
Network Monitoring (Grid Visibility)	Option 2c	2.28	2.28	2.28	2.28	2.28	**11.40**
Network Upgrades for DOE connected customers (Hosting Capacity)	Option 2c	-	0.5	-	-	0.5	**1.00**
LVDERMS (Dynamic Connections)	Option 2c	1.23	0.25	-	-	-	**1.49**
Telemetry Hub (Dynamic Connections)	Option 2c	0.93	0.93	-	-	-	**1.86**
Total		6.14	8.20	6.96	3.99	4.49	**29.78**

[11] 10% accounts for customer choice and the uncertainty about how many will choose a DOE over an export tariff.