Business case: CER integration

2025-2030 Regulatory Proposal

Supporting document 5.7.4

January 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BAU	Business as usual
Capex	Capital expenditure
CAB	Community Advisory Board
CCP	Consumer Challenge Panel
CEC	Clean Energy Council
CECV	Customer Export Curtailment Value
CER	Customer Energy Resources
CSIP-AUS	Common Smart Inverter Profile - Australia
CRC	Cooperative Research Centre
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DERIWG	DER Integration Working Group
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EVC	Electric Vehicle Council
EVM	Enhanced Voltage Management
EWOSA	Energy and Water Ombudsman of South Australia
HV	High Voltage
ISP	Integrated System Plan
LDC	Line-Drop Compensation
LV	Low Voltage
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
OPCL	Off-Peak Controlled Load
Opex	Operating expenditure
PV	Photovoltaic (solar)
QoS	Quality of Supply
RACE for 2030	Reliable Affordable Clean Energy for 2030
RCP	Regulatory Control Period
SA	South Australia
SACOSS	South Australian Council of Social Services
SIRG	Solar Industry Reference Group
TEC	Total environment Centre

ToU	Time-of-Use
UTS	University Technology Sydney
VPP	Virtual Power Plant

1 About this document

1.1 Purpose

This document sets out the business case for investment in additional export capacity, primarily in the Low Voltage (**LV**) network, to manage the forecast demand for export services (the use of the network by customers with solar and battery storage to feed in energy) in 2025-30.

1.2 Expenditure categories

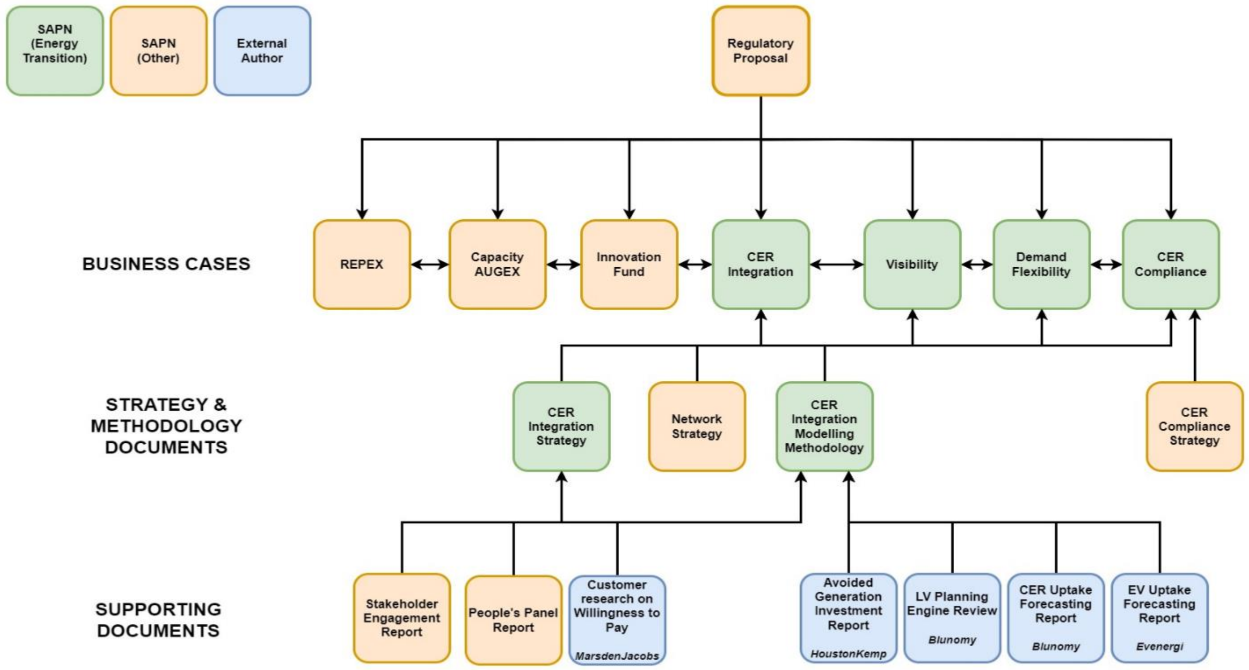
- Network capex: DER capex
- Non-network capex

1.3 Related documents

Table 1: Related documents

Ref	Title
1	5.4.2 - Augex Capacity - Business case
2	5.7.3 - CER Compliance - Business case
3	5.7.5 - Demand Flexibility - Business Case
4	5.7.6 - Network Visibility - Business Case
5	5.7.7 - Innovation Fund - Business case
6	5.7.9 - CER Integration Modelling Methodology
7	5.7.11 - EV Uptake Forecasting - Consultant Report
8	5.7.12 - CER Uptake Forecasting - Consultant Report
9	5.7.13 - Avoided Generation Investment Report - Consultant Report
10	5.7.14 - LV Planning Engine Review - Consultant Report
11	5.7.15 - CER Integration Strategy

Figure 1: Related documents



2 Executive summary

Overview

This business case recommends new expenditure in the 2025-30 Regulatory Control Period (**RCP**) to add additional export capacity, primarily in the LV network, to meet the forecast growth in demand for export services (the use of the network by solar and battery customers to feed in energy) and maintain export service levels in 2025-30. Total capital expenditure (**capex**) proposed for new export capacity is **$46.4** million over the 2025-30 RCP[1].

Our Customer Energy Resources (**CER**) integration expenditure forecast also includes **$14.4** million capex and an additional **$3.85** million in operating expenditure (**opex**) that is not associated with adding new export capacity, but which is necessary expenditure associated with the ongoing provision of the export service through the 2025-30 RCP.

Drivers for change

South Australia has the highest ratio of rooftop photovoltaic (**PV**) generation to operational consumption of all the National Electricity Market (**NEM**) regions. In December 2023, installed rooftop PV capacity stands at 2.56GW and continues to grow strongly as homes and businesses respond to high energy prices.

The distribution network has a finite capacity to accommodate the reverse power flows (export energy) arising from rooftop PV systems and batteries. Based on forecast uptake of rooftop solar and behind-the-meter batteries, our network modelling indicates a progressive increase in the incidence of export constraints in the network during the 2025-30 RCP, that is, periods in which local reverse power flows exceed the capacity of the local network.

Maintaining export service performance

Our long-term strategy for CER integration[2] is first to pursue a range of non-network solutions to manage export demand such as tariffs, incentives and our demand flexibility, CER compliance and network visibility programs. These initiatives help improve underlying utilisation of hosting capacity and act to change the drivers of demand, increasing daytime load, reducing evening peak demand, better matching customer load profiles to intermittent renewable generation and increasing utilisation of existing capacity.

Where these approaches are not sufficient to prevent the network's export capacity limits from being exceeded, our primary operational tool to manage reverse power flows and maintain reliability and quality of supply in the 2025-30 RCP will be our *flexible exports* capability, a non-network solution that can dynamically reduce customer export limits in specific locations during times when the network is constrained. This curtails solar output to maintain the net reverse power flow at the local LV transformer within limits.

With flexible exports we can substantially reduce (but not fully eliminate) the need for investment in additional export capacity in future, but at the expense of a progressive decline in the level of service export customers receive in congested areas year-on-year as the frequency of curtailment increases. To maintain export service levels and meet demand for the export service as solar uptake grows, we need to make targeted investments to increase export capacity in congested areas of the network.

We engaged with customers to understand the future demand for the export service, that is, the level of service that export customers want and are willing to pay for on an ongoing basis, taking into consideration the potential bill impacts from different levels of investment associated with different service levels. Through this engagement process our customers considered a range of options and have indicated that their

[1] All figures in this business case are in June $2022

[2] **Supporting document 5.7.15 - CER Integration Strategy**

preference is for us to invest to maintain export service levels at or above 95% for most customers i.e. export customers preference is to not be curtailed more than 5% of solar hours[3] during the year. This is a slight reduction in the export service level currently received by flexible export customers today, which is circa 98%.

Our proposed capital program

Our proposed capital program (the option recommended in this business case) is based on a target to maintain export service levels at or above 95% for 95% of customers through the 2025-30 RCP. The level of investment required has been forecast using an improved version of the modelling methodology used in our Regulatory Proposal for the 2020-25 RCP referred to as the *LV Planning Engine*. This tool models future power flows in the LV network to forecast future export constraints and seeks to produce an optimal sequence of network augmentation works to resolve them.

Our proposed work program includes targeted upgrades in the LV network (transformer replacements, infills, re-tapping, phase balancing, etc.) and additional Line Drop Compensation (**LDC**) equipment at several substations.

Costs and benefits

The cost of our proposed export capacity program is $46.4 million (**capex**) over the 2025-30 RCP. In a 25-year cost / benefit analysis (2025-2050) the program generates forecast benefits of $113.3 million arising primarily from the value of avoided curtailment, calculated using a modified version of the Customer Export Curtailment Value (**CECV**), giving a positive benefit versus cost result in Net Present Value (**NPV**) terms over the 25-year evaluation period of $18.9 million.

Options and sensitivities

We modelled the costs and benefits of alternative investment plans targeting a lower (90%) or a higher (98%) level of export service, as well as a ‘minimum investment’ base case. Our recommended option is preferred because it reflects the service level customers have indicated they want, aligns with the level of expenditure endorsed by our People’s Panel and returns the highest net benefits to all customers of the options considered.

The above costs and benefits are based on the CER uptake forecast from the Australian Energy Market Operator (**AEMO**) Integrated System Plan (**ISP**) 2022 Step Change scenario. We have also modelled outcomes under the ISP Slow Change and Strong Electrification scenarios.

Related work

Our CER integration expenditure forecast also includes $14.4 million capex and $3.8 million opex of unavoidable expenditure related to the export service. This includes ongoing systems costs associated with our flexible exports program, costs associated with our obligations under the SA Government Smarter Homes regulations and the installation of additional voltage regulators in the 66kV/33kV sub-transmission network required to maintain voltage compliance at ElectraNet connection points at times of minimum demand. These costs are included in the base case for this business case.

Our proposed export capacity expenditure is related to, but separate from, expenditure for the following programs described in other business cases:

- our proposed CER Compliance program[4];

[3] For the purpose of defining export service levels we define ‘solar hours’ as the hours from 9am to 5pm. Further information is provided in the body of this document.

[4] 5.7.3 - CER Compliance - Business case.

- our proposed demand flexibility enablement program[5];
- our proposed network visibility program[6];
- our business-as-usual (BAU) LV network maintenance program[7]; and
- our proposed innovation fund[8].

3 Background

3.1 The scope of this business case

This business case recommends new expenditure in the 2025-30 RCP to meet and manage the forecast growth in demand for export services (the use of the network by customers with solar and battery storage to feed in energy) in 2025-30.

The most significant component is our export capacity program, a program of targeted investments to add additional export capacity to resolve constraints arising from the forecast continued growth in small-scale solar and batteries. This involves upgrading and replacing network assets, primarily in the LV network, and improvements to voltage management at select substations and in the High Voltage (**HV**) network.

This business case considers several options for the scope of this work program. Different levels of investment lead to different outcomes, which we consider both in terms of the frequency of export curtailment experienced by solar customers due to network constraints in the period (the export service level) and also the broader economic value lost due to this curtailment, calculated using the Australian Energy Regulator's (**AER's**) CECV methodology. Our preferred option aligns with customer expectations established through our consumer and stakeholder engagement program and confirmed in the recommendation of our People's Panel and involves a total expenditure of $46.4 million (capex) over the 2025-30 RCP[9].

In addition to the above, our proposal includes ongoing expenditure to maintain and scale the systems we have developed in the 2020-25 RCP that support our flexible exports dynamic connection capability for solar, to maintain other existing systems associated with CER integration including the distributed energy resources (**DER**) register and systems associated with the SA Government's Smarter Homes requirements[10], and some specific works to maintain voltage compliance at the sub-transmission level. The total expenditure in these areas is $14.4 million capex and $3.85 million opex over the period. This expenditure is required under all scenarios and options and is considered unavoidable in 2025-30, hence it is included as part of the base case for the options analysis presented in this business case.[11]

This business case also has linkages with other related expenditure described elsewhere in our proposal:

- our proposed CER Compliance program[12];

5 5.7.5 - Demand Flexibility - Business Case.

6 5.7.6 - Network Visibility - Business Case

7 Included in 5.4.2 - Augex Capacity - Business case

8 5.7.7 - Innovation Fund - Business case

9 Figures are in June $2022

10 The South Australian Government Smarter Homes regulations introduced in 2020 establish specific requirements for solar installations in South Australia to facilitate remote disconnection or export curtailment by SA Power Networks during minimum demand contingencies. For details, see: Regulatory changes for smarter homes | Energy & Mining (energymining.sa.gov.au) (accessed July 2023)

11 Refer section 5.4.1

12 5.7.3 - CER Compliance - Business case

- our proposed demand flexibility enablement program[13];
- our proposed network visibility program[14];
- our business-as-usual (BAU) LV network maintenance program[15]; and
- our proposed innovation fund[16].

3.2 Drivers for change

South Australia has the highest ratio of rooftop PV generation to operational consumption of all the NEM regions. In December 2023 more than 350,000 homes and businesses have installed rooftop solar, more than one in three premises. Uptake continues to grow strongly as homes and businesses respond to high energy prices, while falling system costs mean that the average system size is also increasing each year. Installed rooftop PV capacity currently stands at 2.56 GW, making rooftop solar the largest source of generation in the state.

As solar uptake has continued to grow, we now regularly experience reverse power flows across large segments of the network during mild and sunny conditions. We reached a global milestone in October 2021 when the net load on the entire distribution network fell below zero for the first time, as high solar output, combined with low underlying demand, saw our network become a net exporter of energy for a short period in the middle of the day. This has occurred numerous times since, with increasing frequency and duration, with the highest net negative demand on the distribution network recorded to date being -385 MW in October 2023.

State-wide minimum operational demand (which includes transmission-connected loads) reached a new record low of just 21 MW on 16 September 2023, with distributed PV accounting for 98.5% of the state's electricity demand at that time[17], as shown in Figure 2 below. Operational demand in South Australia may fall below zero before the end of 2023.

13 5.7.5 - Demand Flexibility - Business Case

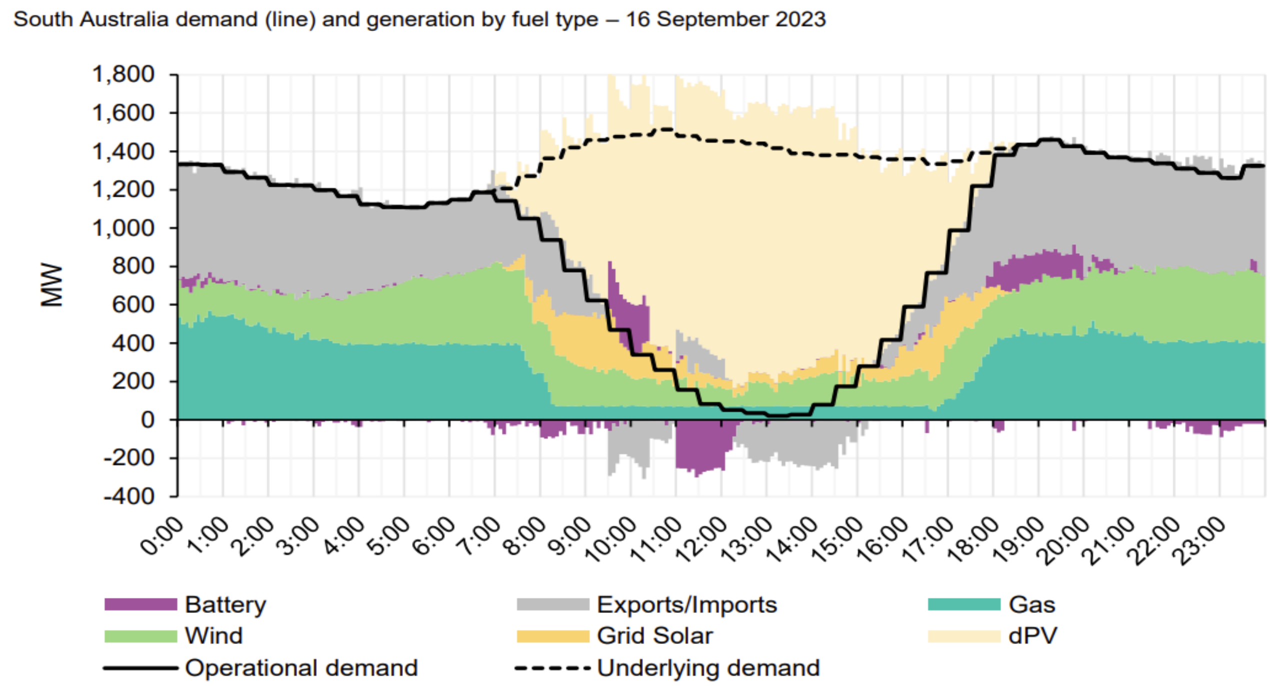
14 5.7.6 - Network Visibility - Business Case

15 Included in 5.4.2 - Augex Capacity - Business case

16 5.7.7 Business case: innovation fund

17 AEMO, *Quarterly Energy Dynamics Q3 2023*, accessed at https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf?la=en, accessed November 2023

Figure 2: SA Operational Demand and Generation mix on 16 September 2023 (Source: AEMO)[18]



No other large-scale electricity network in the world is operating in this way, and it continues to pose unique challenges, both for SA Power Networks in operating the distribution network and for AEMO in balancing supply and demand and maintaining power system security, particularly during spring and early summer.

South Australia also continues to lead the nation in the uptake of small-scale batteries connected at the distribution network, with growth driven by the SA Government's successful Home Battery Scheme which provided subsidies for home batteries from 2019 to 2022. There are now more than 48,000 small-scale batteries in homes and businesses in South Australia, more than any other state, with an aggregate capacity of more than 240 MW. Around a third of these are enrolled in Virtual Power Plant (**VPP**) schemes which allow them to be centrally controlled and operated, enabling customers to earn money by using their batteries to trade in the NEM wholesale energy market and to help stabilise the power system.

Figure 3 below shows historical and forecast uptake of solar PV and batteries in South Australia.

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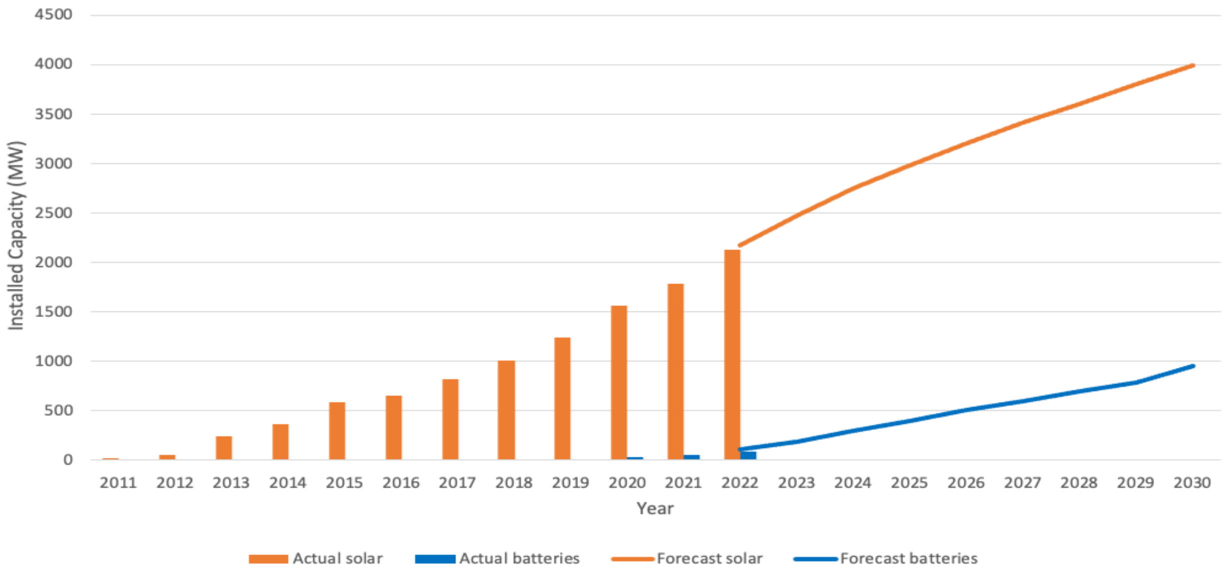
[18] Ibid.

Figure 3: SA Consumer Energy Resource forecasts, AEMO ISP 2022 Step Change scenario



The distribution network has a finite capacity to accommodate the reverse power flows (export energy) arising from rooftop PV systems and batteries. This 'hosting capacity' is limited by two things:

1. **Voltage constraints**

   SA Power Networks has a regulatory obligation to maintain supply at the customer connection point between 216V and 253V (the range specified in Australian Standard AS 60038)[19]. Rooftop PV and battery inverters must raise voltage to feed energy back into the grid. This increases the dynamic range of voltage variation in the LV network as voltage drops at times of high demand and rises at times of low demand and high rooftop PV output (e.g. mild, sunny days). In areas of high solar penetration, high levels of daytime export energy can cause voltage at customer connection points to exceed the range specified in AS 60038. This causes customer inverters to trip off and can cause quality of supply issues for other customers in the area (including those without rooftop PV), including damage to customer equipment. Daytime over-voltage is almost always the first issue that arises in areas of high solar uptake and the initial cause of export constraints.

2. **Thermal constraints**

   As rooftop PV penetration grows in a local area, reverse current in the middle of the day ('peak generation') can become greater than the traditional summer afternoon peak current draw that the network was designed for. When reverse current exceeds the thermal rating of an asset like an LV transformer, fuses will operate, causing a supply outage for customers in the area.

These issues arise in part because the network was designed for peak demands that are reduced, in aggregate, by natural diversity in customer usage patterns, whereas rooftop PV output lacks this diversity; all rooftop PV systems in the same local area are generally exporting at full power simultaneously in the middle of the day. VPPs that aggregate many customers' individual energy resources under central control present particular challenges in this regard, because a VPP operator who triggers the simultaneous discharge of multiple batteries in the same local area, for example in response to a market price signal, can cause a very large reverse power flow in the local network.

19 SA Electricity (General) Regulations 2012, under the Electricity Act 1996, version 1.7.2023, section 46(a).

Based on forecast rates of uptake of rooftop solar and behind-the-meter batteries, our network modelling indicates a progressive increase in the incidence of export constraints in the network in the 2025-30 RCP, that is, periods in which local reverse power flows exceed the capacity of the local network.

Our primary operational tool to manage reverse power flows and maintain reliability and quality of supply in the 2025-30 RCP will be to use our flexible exports capability to dynamically reduce customer export limits in locations and at times when the network is constrained, to maintain net reverse power flows at local LV transformers within limits. From July 2023, SA Government regulations came into effect requiring all new solar systems installed in South Australia to be compatible with flexible exports[20]. By the commencement of our next RCP in July 2025, we expect the majority of customers connecting new solar and batteries to do so under a flexible connection arrangement.

3.3 Our performance to date

Until recently, customers connecting solar to the network in South Australia have been automatically approved to connect systems of up to 5 kW per phase with no export limitations, in line with standard industry practice and AS 4777.

Solar customers have historically enjoyed a high level of export service performance, defined as the percentage of time through the year that they are able to export all surplus energy from their systems without constraint. Prior to 2016, export service performance was close to 100% as the amount of solar export was within the intrinsic hosting capacity of the network in most areas. Daytime over-voltage issues were relatively uncommon, with 300-500 customer-reported issues each year, peaking in springtime, investigated and remediated as part of our ongoing Business-as-Usual (**BAU**) LV network Quality-of-Supply (**QoS**) program.

As can be seen in Figure 4 below, from 2016 to 2020 we began to see a rapid escalation in customer-reported over-voltage issues as solar PV penetration began to exceed intrinsic hosting capacity in areas across the network. The seasonal nature of this issue is apparent in the chart, with over-voltage problems peaking in spring and early summer when solar exports are highest due to high levels of sunshine combined with low underlying load associated with mild temperatures. During the 2016-2020 period customer export service performance declined for those customers experiencing over-voltage as they experienced inverters tripping or self-curtailing via AS 4777 protection settings. Even at this time, however, export service levels remained generally high across the network. A study by the University of New South Wales (UNSW) analysed the impact of daytime over-voltage on export service performance in South Australia for a sample of 500 solar PV systems and 996 battery sites in 2020 and found that the impact was, on average, around 13kWh in lost export annually for solar PV customers and around 5kWh for battery customers, or less than 1% of total generation[21]. The study found there was considerable variation between customers in the level of service they received, with some customers losing up to 20% of their total generation due to over-voltage tripping.

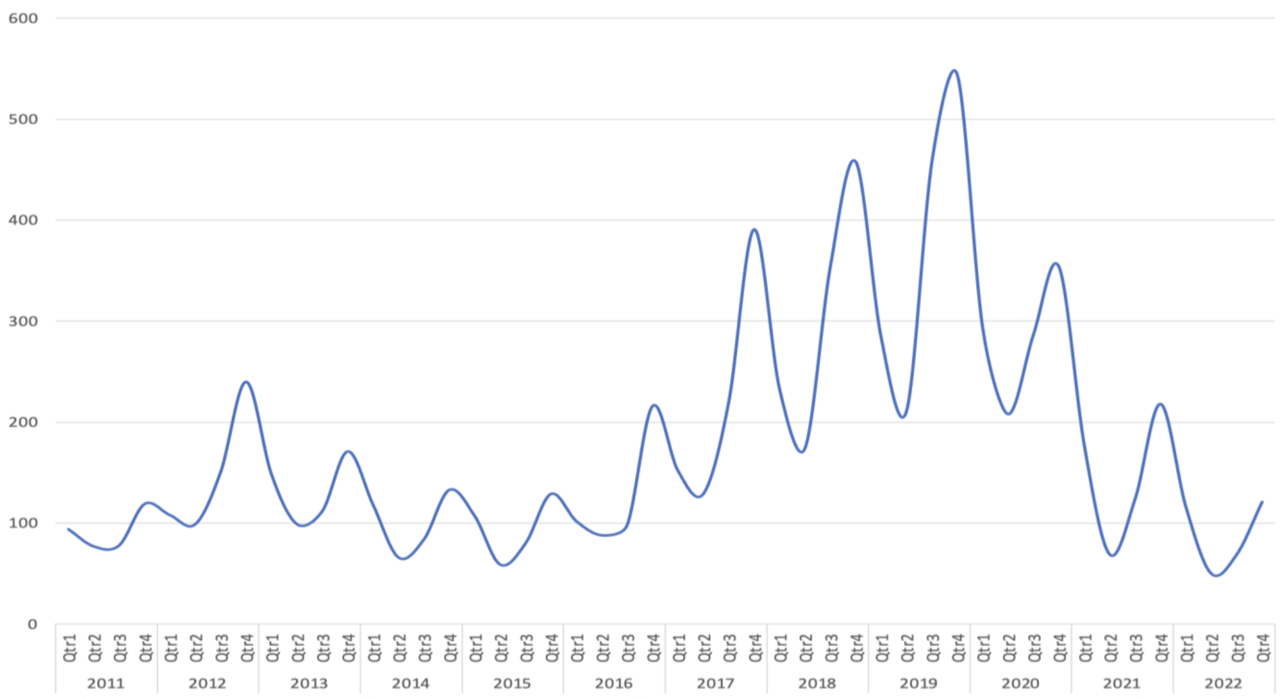
In 2020, as part of our response to urgent system security risks in South Australia, we undertook a $10 million capital program to implement Enhanced Voltage Management (**EVM**) across 140 of our larger zone substations. The primary driver at the time was to develop an emergency voltage raise capability to rapidly shed large amounts of small-scale solar if required to support AEMO during a minimum demand contingency event. The equipment upgrades made via this program also, however, enabled us to activate LDC at these substations, a technology that automatically raises or lowers the voltage setpoint at the substation depending on load. This has the effect of reducing daytime voltage rise due to solar PV without creating under-voltage conditions at times of peak demand. As can be seen in Figure 4, this has proven to be very

[20] For details, see: Regulatory changes for smarter homes | Energy & Mining (energymining.sa.gov.au) (accessed July 2023).

[21] UNSW Sydney, *Curtailment and Network Voltage Analysis Study (CANVAS), Final Report 2021*, project undertaken as part of the RACE for 2030 CRC.

beneficial in mitigating customer over-voltage issues in the short term, with customer over-voltage enquiries falling as the EVM program rolled out through 2020 and 2021, returning to 2016 levels by 2022.

Figure 4: Customer high-voltage enquiries 2011 - 2022



Modelling of network hosting capacity and future solar uptake undertaken in 2017 showed that export service levels would continue to decline over the long term, with progressively more material customer impact, unless we either invested in adding more export capacity to the network or changed our approach to network connections for new solar. This became the basis of our 2018 LV Management Business Case[22], which set out the case for transitioning from static export limits for new solar customers to dynamic limits, now known as flexible exports or Dynamic Operating Envelopes (**DOEs**). This business case was the centrepiece of our CER management strategy in our Regulatory Proposal for the 2020-25 RCP. The approach taken was industry-leading at the time, foreshadowing the methodology later described in the AER's DER Integration Guidance note[23] and introducing the concept of a market value of customer curtailment akin to the CECV.

Since 2020 we have successfully executed the plans set out in our previous Regulatory Proposal, becoming the first distribution network service provider (**DNSP**) in Australia to go live with flexible export limits in 2019 with an initial tranche of 1,000 customers in our award-winning Advanced VPP Grid Integration Trial[24]. We progressed to our second-stage Flexible Exports for Solar PV pilot[25] in September 2021 using the new national Common Smart Inverter Profile - Australia (**CSIP-AUS**) communications standard[26] which we helped to develop. Since that time, customers connecting solar in certain congested areas of our network have had the option to connect with a flexible export connection, which allows a dynamic export limit of up to 10 kW per phase, or to opt for a 1.5 kW static limit.

22 SA Power Networks, *LV Management Business Case*, attachment 5.18 to our 2020-25 Regulatory Proposal, 2018.

23 AER, *Distributed energy resources integration guidance note*, June 2022.

24 See: https://arena.gov.au/projects/advanced-vpp-grid-integration/, accessed July 2023.

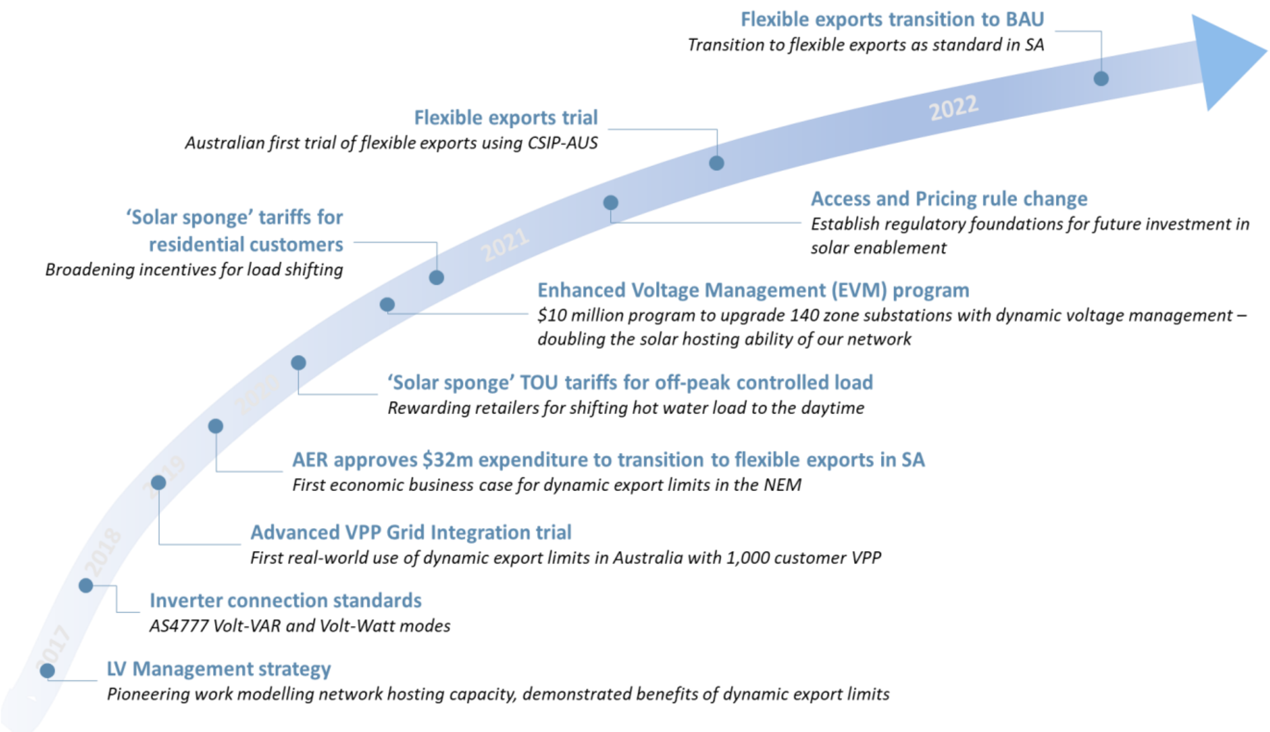
25 See: https://arena.gov.au/projects/sa-power-networks-flexible-exports-for-solar-pv-trial/, accessed July 2023

26 The *Common Smart Inverter Profile – Australia* (CSIP-AUS) is a standard that defines how the IEEE 2030.5 communications protocol should be used be DNSPs to communicate flexible export limits to customer equipment. For further information see: https://arena.gov.au/assets/2021/09/common-smart-inverter-profile-australia.pdf, accessed July 2023

At the present time (December 2023), flexible export connections are available only in specific areas of the network where solar penetration has already exceeded the intrinsic capacity of the local network and some level of dynamic management of exports is required. We have around 1,500 solar customers on this connection arrangement today[27]. Since 1 July 2023, under the SA Government's Smarter Homes regulations, all new solar PV systems in South Australia have been required to support the CSIP-AUS standard and be compatible with flexible exports, and we are making the offer available in progressively more areas of the network. We expect the number of customers on the scheme to escalate rapidly through 2024 and by the end of 2024 we expect that flexible exports will be the default connection arrangement for new solar customers connecting anywhere on the network.

Our CER integration journey since 2017 is illustrated in Figure 5 below. As well as the initiatives described above, it also shows the introduction of AS 4777 Volt-VAr and Volt-Watt modes as mandatory in our connection agreement in December 2017, our successful proposal to change the National Electricity Rules (**NER**) in support of the Australian Energy Market Commission's (**AEMC's**) *DER access, pricing and incentives* regulatory reforms, and the introduction of Australia's first 'solar sponge' Time-of-Use (**ToU**) tariffs in 2020 to incentivise shifting of loads into the middle of the day. Since these tariffs were introduced we have seen retailers respond by shifting controlled-load hot water loads (which we now allow retailers to schedule) from overnight into the daytime.

Figure 5: Our CER integration journey



3.3.1 Progression from our 2020-25 Regulatory Proposal

In developing our 2020-25 Regulatory Proposal we first undertook a detailed modelling exercise to build a deeper understanding of the export hosting capacity of our network. This methodology has been further developed since, and underpins the modelling used in this business case.

The plans put forward in our 2020-25 Regulatory Proposal focused on fitting more solar on to the network we have, managing immediate issues and risks and building the foundations for the continued uptake of CER into the future. Since then, we successfully delivered on these plans, developing flexible exports, implementing data analytics capabilities to improve visibility of our LV network using data from smart meters

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27 Including customers with systems installed or approved, pending installation.

and other devices and transitioning to 'solar sponge' tariffs. We have also put in place other key foundations including a significant uplift in our voltage management capabilities, a range of emergency backstop measures for minimum demand contingencies, and our successful rule change proposal in support of the AEMC's *DER access, pricing and incentives* reforms.

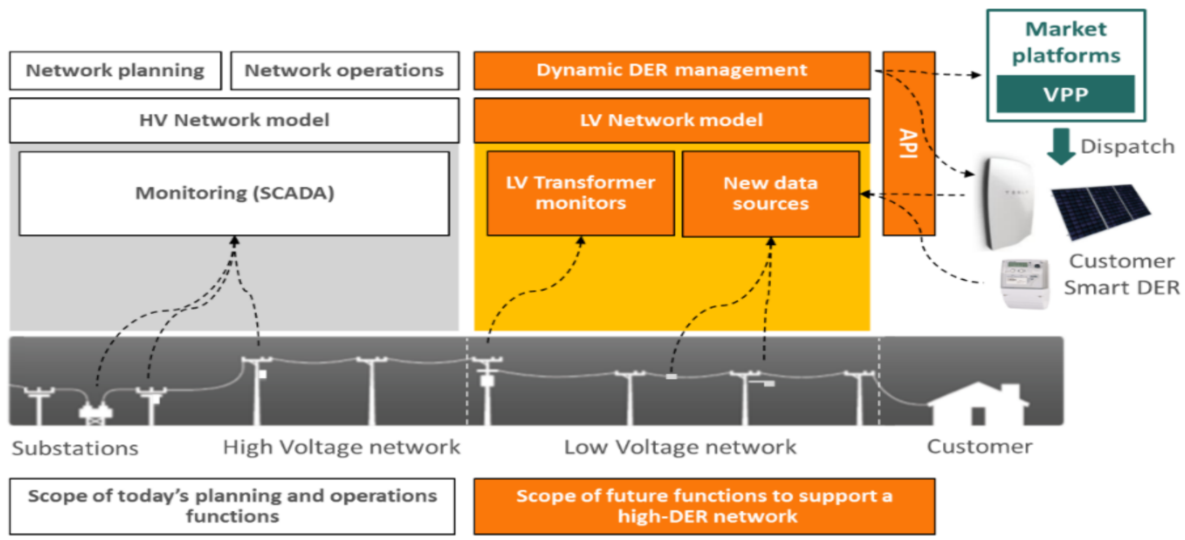
Looking beyond 2025 we see the pace of change accelerating as we move into a critical period in South Australia's journey to net zero emissions. As well as the continued uptake of rooftop solar and batteries, we expect greater activation of small-scale CER through VPPs and other aggregation schemes, supported by reforms to the NEM, increasing connection of grid-scale DER to our network, the emergence of flexible load devices such as smart hot water, very significant growth in sales of Electric Vehicles (EVs) and the start of a broader shift to electrification in homes, workplaces and industry.

Our overarching goal is to ensure that we have sufficient capacity in the network to enable this next phase in South Australia's energy transition and to enable our customers to achieve the value they are seeking from their ongoing investments in CER. To this end, our 2025-30 Regulatory Proposal builds on the solid foundations established in the last five years to continue the transition to a truly two-way network. Having put in place the foundational capabilities that enable us to maximise utilisation of the capacity that we have, our focus has shifted to planning for the progressive, prudent and efficient addition of export capacity to the network as required to keep pace with continued growth in demand.

3.3.2 Performance against plans for 2020-25

Our 2020-25 Regulatory Proposal set out a ~$35 million program of expenditure[28] to develop the new capabilities and systems shown in orange in the figure below to manage high levels of CER connected to the LV network, none of which existed at the time.

Figure 6: New capabilities required for CER integration (figure from our 2018 *LV Management Business Case*[29])



As at December 2023 all of these new systems and capabilities have been developed and we transitioned from field trials to production for our core flexible exports capability, ahead of the schedule set in our 2020 proposal. We are on track to complete these programs as planned and on budget by the end of the current RCP.

28 Total cost of our LV management program and LV transformer monitoring program in $2020 excluding business overheads. Refer *DER management expenditure overview*, supporting document 5.14 to SA Power Networks' 2020-25 Revised Regulatory Proposal, accessed at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/revised-proposal

29 SA Power Networks, *LV Management Business Case*, attachment 5.18 to our 2020-25 Regulatory Proposal, 2018.

3.3.3 Export service levels today

As described above, solar customers in South Australia have historically enjoyed a high level of export service performance. In summary:

- prior to 2016, export service performance was close to 100% across the network as solar exports were within the network's intrinsic capacity and export constraints were rare;
- from 2016 to 2020 service performance declined as solar penetration rates began to exceed hosting capacity in some areas and customers began to experience curtailment due to their inverters tripping or self-curtailing in response to excessive daytime voltage levels. Data from the UNSW CANVAS study suggests that average service levels declined to 98-99% during this period, but some customers experienced service levels of 80% or lower;
- our 2020-2021 Enhanced Voltage Management (EVM) program significantly improved voltage control across 140 zone substation areas and, on the evidence of customer enquiry rates, had reduced customer over-voltage issues back to 2016 levels by 2022;
- as solar penetration continues to increase our modelling shows that new export constraints will continue to emerge across the network, even factoring in the beneficial effects of daytime load shifting in response to ToU tariffs, growth in home batteries and EVs, EVM and other measures. Our strategy is to transition to flexible exports as our standard connection offer so that, in future, these constraints can be managed actively by reducing customers' solar output before voltage rise becomes excessive and customer inverters trip off;
- so far, our cohort of flexible export customers in congested network areas have had their exports limited for less than 2% of solar hours during the year, that is, they currently receive an export service level of at or above 98% according to our preferred service level measure[30]. An indicative service level is communicated to customers at the time that they apply to connect a new rooftop solar system[31], to give some guidance on the levels of congestion in their area.

3.4 Industry practice

We consider that our approach to CER integration aligns with industry best practice in Australia. In fact, noting that South Australia is at the forefront of the transition to a very high-CER electricity system, in many cases practices established in South Australia are shaping best-practice nationally. Our approach includes the following:

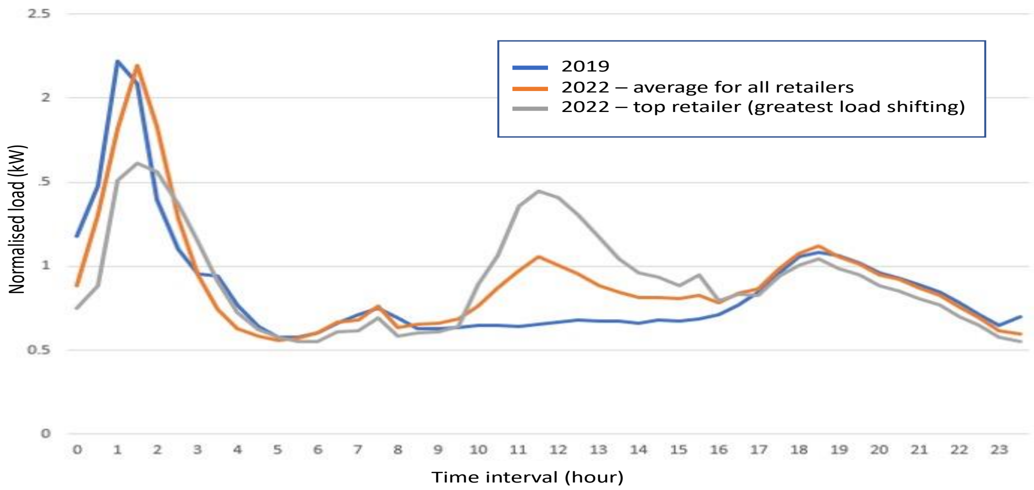
- we take a holistic approach to CER integration. Our first strategy is to seek to maximise the opportunity to shift residential and commercial loads to the daytime to increase the level of solar self-consumption behind the meter. This is the highest-value use of solar for customers and helps reduce the need for additional daytime export capacity at the LV transformer and upstream network assets. Two areas of particular focus for us at present are encouraging electric hot water loads to shift from overnight to daytime, as this is one of the largest loads and largest consumers of energy for customers that use it, and ensuring that future EV loads are kept out of peak times and, where possible, moved to the daytime;
- our approach is 'market first, technical limits second'. We were the first Australian DNSP to introduce ToU tariffs with an extra-low 'solar sponge' rate during the middle of the day to create the opportunity for customers to save money by shifting discretionary loads to the daytime. In 2020 we relinquished control of scheduling off-peak controlled load (**OPCL**) hot water and gave responsibility to retailers, moving from our previous flat overnight rate to a 24-hour ToU 'solar sponge' controlled load tariff. This enables and encourages retailers to shift hot water loads to take advantage not only of our low network

30 Refer Appendix 0 for further details of the calculation of our service performance measure.

31 When they apply to connect, customers in a congested area receive an indication of the historical export service performance in their area over the last 12 months. While it is made clear that this is not a guarantee of future performance, it provides customers with an indication of the level of local network congestion.

tariff, but also increasingly negative daytime wholesale prices in South Australia. Since then, we have observed a progressive shift in retailer-controlled OPCL hot water loads from overnight to the daytime, as shown in Figure 7, and we are actively engaging with retailers to encourage this;

Figure 7: Residential load profiles showing shifting of overnight hot water loads to the daytime by electricity retailers in response to our introduction, in 2020, of 'solar sponge' tariffs for controlled load hot water[32]



- our proposed 'Diversify' trial tariff aims to combine price signals with a DOE control signal for residential EV chargers. This aligns with findings of a recent study by the University of Melbourne on the network impacts of EV charging[33] which found that ToU tariffs were highly effective at keeping EV charging loads out of peak times but, at forecast long-term levels of EV uptake, should ideally be combined with control signals and load shaping to avoid future 'second peak' issues at tariff price boundaries. This and other related initiatives are described in our separate demand flexibility business case[34];
- our Australian renewable energy agency (**ARENA**)-funded Market Active Solar trial[35] seeks to demonstrate how distribution networks can work with electricity retailers to support retailer market-based solar curtailment offers. In this trial two major retailers are offering customers a financial incentive if they allow the retailer to control their solar inverter to curtail output at times when there is excess solar generation in the system and the wholesale price is negative. We consider that activating passive rooftop solar to respond to market price in this way has tremendous potential to increase the ability of the market to manage supply and demand, reducing the future need for additional network export capacity investment and for emergency backstops[36]. In this trial we are demonstrating how this market-based curtailment interoperates with, and is complementary to, DNSP flexible export limits;
- we are actively exploring the potential for non-network solutions (e.g. batteries and load turn-up services) to manage export constraints and avoid or defer future capital investment in increasing export capacity. We supported trials of the voltage support capabilities of grid connected batteries as part of

32 The chart shows the average load profile for a sample of electric hot water customers (normalised to remove differences in customer size) in 2019, prior to the change in tariff arrangements, and in 2022, two years after the introduction of the 'solar sponge' tariff for controlled load in 2020. Averaged across all energy retailers in the sample set, some shifting of overnight load to the daytime can be observed (orange line). There is considerable variation between retailers in the extent to which they have responded to the new price signal, with the most proactive retailer (grey line) having shifted considerably more load to the daytime than the average.

33 University of Melbourne, *EV Integration project*, accessed at: https://electrical.eng.unimelb.edu.au/power-energy/projects/ev-integration, June 2023

34 5.7.5 Business case: demand flexibility

35 See https://arena.gov.au/projects/sa-power-networks-market-active-solar-trial/

36 Noting that emergency backstop measures will always be required to manage contingency events where the market cannot provide the speed and/or magnitude of response required to maintain system security – as has historically been the case with emergency load shedding.

the University of Adelaide's Australian Energy Storage Knowledge Bank project[37] and we are currently exploring the broader potential of community batteries in South Australia though our engagement with the Australian Government's *Community batteries for household solar* program[38]. We have also collaborated with retailers and VPP operators to explore the potential for third-party VPPs to provide support for network voltage management and the management of export constraints through our participation in several ARENA-funded VPP trials in South Australia[39]. As CER penetration and VPP participation rates grow in the 2025-30 RCP we will continue to actively seek opportunities to engage non-network solutions to defer capex where it is efficient to do so;

- we are working actively with the solar industry in South Australia to improve compliance to AS 4777 and other CER connection requirements. The low level of compliance in installed equipment today has been identified as a key issue impacting both network hosting capacity and system security[40]. Our activities in this area are described in our separate compliance business case[41];
- the rollout of LDC to more than 140 major zone substations through our EVM program has brought our substation voltage management capabilities closer to industry best-practice. It has allowed us to reduce average voltage levels across the network at times of low demand, both in the daytime and overnight, something industry stakeholders have been calling on DNSPs to do in recent years. Our 2025-30 investment program set out in this business case includes a further investment to roll out this capability to more substations, as well as related work to re-tap distribution transformers that will enhance the efficacy of the system;
- we pioneered the use of flexible export limits in the NEM based on the CSIP-AUS national standard, and are the first Australian DNSP to launch a flexible connection offer as standard for residential solar customers connecting to congested parts of the network. Flexible exports presents a step change in customer access to available export capacity. It significantly increases utilisation of the latent export capacity in the network year-round and provides a much higher grade of export service for customers in congested areas than alternatives based on static export limits. It allows us to actively manage reverse power flows in congested areas at times of minimum demand to maintain quality of supply and prevent inverter tripping or asset overloads. This, in turn, allows for a measured, proactive, targeted and efficient approach to investment in new export capacity to relieve constraints in areas where curtailment with flexible exports is high, where this is required to maintain export service levels to the standard export customers want and are willing to pay for, and where it is efficient to do so. This is the approach set out in this business case; and
- our approach to CER integration investment and the valuation of export energy, as set out in this business case, aligns with best practice set out in the AER's DER Integration Expenditure Guidance Note and uses the AER's CECV. Our progressive investment in export capacity to manage customer demand for the export service and to maintain export service levels, and our proposed recovery of costs associated with this investment through export tariffs in the 2025-30 RCP, have been guided by the intent of the AEMC's 2021 *DER access, pricing and incentives rule change*[42] and the AER's Export Tariff Guidelines[43].

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37 See: https://www.adelaide.edu.au/energy-storage/

38 See: https://www.dcceew.gov.au/energy/renewable/community-batteries

39 Including the Tesla/Energy Locals VPP and VPPs operated by retailers AGL and Simply Energy

40 See AEMO, *Compliance of Distributed Energy Resources with Technical Settings*, April 2023, available at: https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-connections/compliance-of-der-with-technical-settings , accessed July 2023

41 5.7.3 - CER Compliance - Business case

42 AEMC, Access, pricing and incentive arrangements for distributed energy resources, rule change, 2021, accessed at https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources

43 AER, *Export Tariff Guidelines*, May 2022

4 The identified need

The AEMC's 2021 *DER access, pricing and incentives* rule change changed the NER to clarify that export services are part of the core distribution services to be provided by DNSPs. The rule change states: *"By removing references in the NER that are specific to the direction of energy, the regulatory framework will give clear guidance that 'distribution services' relate not only to sending energy to customers, but also to customers exporting the energy they generate".*[44]

As set out in section 3.2, customer demand for the export service in South Australia is increasing and is forecast to continue to increase through the 2025-30 period and beyond. Daytime export levels have already reached the limits of network capacity in some areas, and increasing demand will see export capacity exceeded in more areas of the network, and more frequently, in future years if no action is taken. Our modelling shows that is the case in South Australia even after taking into account the impacts of 'solar sponge' tariffs, load shifting, future growth in batteries and EV charging and the beneficial impacts of our other CER integration programs as described in section 3.4 above and in our CER integration strategy.[45]

As the export service is now part of our standard control services, in considering options for how to respond to this situation we have considered the regulatory framework under the NER and the National Electricity Law (**NEL**) and, in particular, the extent to which the associated expenditure is required to achieve the expenditure objectives and reasonably reflects the expenditure criteria, having regard to relevant factors. We have also considered our applicable regulatory obligations and requirements. As a result of these considerations, the identified need is as follows:

- the need to prudently and efficiently meet or manage expected demand for the export service;[46]
- the need to prudently and efficiently comply with all applicable regulatory obligations or requirements pertaining to the provision of the export service to customers[47], which in this case include the following:
    - section 60 of the *Electricity Act 1996* (SA) which requires DNSPs to take reasonable steps to ensure that infrastructure complies with, and is operated in accordance with, technical and safety requirements imposed under regulations, and is safe and safely operated;
    - regulation 46(a) of the *Electricity (General) Regulations 2012* (SA) which requires a DNSP to ensure that its network is designed, constructed, operated and maintained so that at a customer's point of supply the voltage is as set out in AS 60038;
    - clause 5.2.1(a)(3) of the NER which requires a DNSP to maintain and operate its network in accordance with good electricity industry practice and relevant Australian Standards; and
    - clause 5.2.3(b) of the NER which requires a DNSP to comply with the quality of supply standards described in schedule 5.1 of the NER and in accordance with any connection agreement with customers;
- to the extent that there are no applicable regulatory obligations or requirements, the need to otherwise maintain the quality, reliability, security and safety of the export service currently being provided by the intrinsic hosting capacity of SAPNs' distribution network, taking the most economically efficient course of action[48]; and

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44 AEMC, Access, pricing and incentive arrangements for distributed energy resources, rule change, 2021, accessed at https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources.

45 5.7.15 CER integration strategy.

46 This is pursuant to clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the NER.

47 This is pursuant to clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the NER.

48 This is pursuant to clauses 6.5.6(a)(3) and 6.5.7(a)(3) of the NER.

- the need to consider the concerns and preferences of our customers expressed through our engagement process[49] regarding the service level outcome that they would like us to continue to achieve in relation to the export service.

In evaluating options to address the identified need we note that there are interactions between these considerations. One option would be to rely primarily on our flexible exports capability to actively curtail customers' solar to manage reverse power flows in the network. In this way we could, in future, comply with our regulatory obligations and requirements and otherwise maintain quality and reliability of supply without the need for significant investment in additional export capacity[50], but at the expense of a progressive decline in the level of export service performance as customers with flexible exports would see their export limits reduced more frequently and for longer durations year-on-year in order to maintain reverse flows within available capacity.

If we maximise our reliance on solar curtailment and minimise investment in additional export capacity, we may meet our regulatory obligations and requirements and otherwise maintain quality and security of supply but fail to meet or effectively manage customer demand for the export service.

If we are to maintain export service levels in the 2025-30 period in line with customer demand, we will need to make targeted investments to increase export capacity in congested areas of the network where service levels are forecast to decline.

5 Comparison of options

We engaged with customers to understand the future demand for the export service, that is, the level of service that export customers want and are willing to pay for on an ongoing basis. Our engagement, which included a series of 'Focused Conversation' workshops, took into consideration the level of future network investment required to maintain service at the 98% level (reflective of historical performance), or at a range of other service levels, and the corresponding bill impacts.[51]

To estimate the level of investment required to enable different levels of export service we developed a detailed network model, shown in Figure 8 below, to forecast future export capacity expenditure based on forecast future power flows in the LV network. This builds on the hosting capacity analysis and network modelling work we undertook in 2017 and 2018 in developing our 2020-25 Regulatory Proposal, and significant work undertaken since then to develop, extend and refine this modelling to support the calculation of dynamic export limits for flexible export customers.

While our first-generation LV network model was an abstract, statistical model built using the *Transform* network modelling tool developed by UK consultant EA Technology, our second-generation *LV Planning Engine* models hosting capacity and forecasts power flows individually for each of the ~77,000 LV transformer areas in our network.

The LV Planning Engine enables us to forecast the future reverse power flows for any LV transformer in any 30-minute interval from 2025 to 2050 based on postcode-level forecasts of growth in solar, battery storage, EVs, etc. derived from AEMO's ISP scenarios. It then seeks to produce an optimal series of network investments to address forecast export capacity constraints arising in the 2025-30 RCP. This process can be tailored to various goals to explore different investment scenarios, for example to produce the most

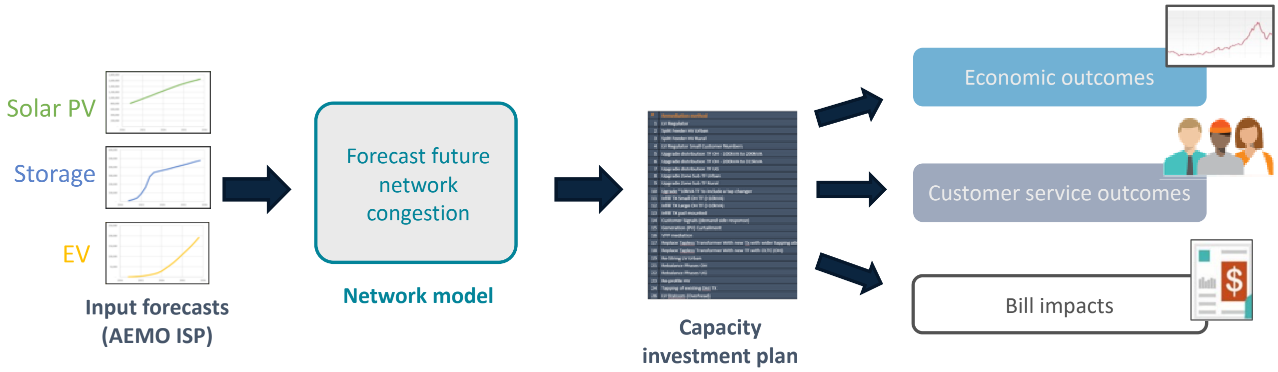
49 This is pursuant to clauses 6.5.6€(5A) and 6.5.7(e)(5A) of the NER.

50 Even with flexible exports we cannot fully prevent issues such as voltage exceedances from occurring in the long term. This is because even when exports are curtailed, rooftop solar generation continues to erode underlying demand through self-consumption behind the meter. Thus some level of ongoing export capacity augmentation is unavoidable as solar uptake grows.

51 Details of our stakeholder engagement program are included in section 6.

economic / efficient series of investments that will maintain export service levels at or above a specific level through the 2025-30 RCP.

Figure 8: Methodology used to forecast future export capacity investment using our LV Planning Engine



In our options assessment we have also considered the estimated market value of different levels of export enablement, calculated by the LV Planning Engine using a modified version of the AER's CECV.

The LV Planning Engine performs a series of steps to produce an investment plan that achieves a particular target level of export service performance across the network. A target service level is expressed as (for example) 'Maintain at least a 95% level of export service for at least 95% of customers'. For this example, the LV Planning Engine proceeds as follows:

1. Apply postcode-level forecasts of CER uptake (solar, batteries, EVs), associated forecast load and generation profiles and other input assumptions to estimate the net load (forward or reverse) on each LV transformer in each 30-minute time interval from 2025 to 2050.

2. Determine the set of LV transformers where forecast reverse power flows exceed hosting capacity at some point in the 2025-30 RCP. For each one, calculate the level of service for export customers in that area each year (the duration of export curtailment), assuming dynamic curtailment with flexible exports is used to cap reverse flows to within hosting capacity whenever exceedances occur. Also calculate the lost economic value of curtailed energy (using a variant of the CECV).

3. For each transformer area where service level declines below the target threshold in the 2025-30 RCP, identify the most economic investment option to resolve the constraint from a set of possible remediations, taking into consideration cost, efficacy and 20-year market benefits (CECV). The output of this stage is the most efficient set of investments that will maintain the target service level for all customers through the 2025-30 RCP.

4. The final step is to rank all proposed investments in order of cost / benefit ratio and exclude the bottom 5% (reflecting the target in this example of 'at least 95% service performance for at least 95% of customers').

It is important to note that, before considering the need for investments in new export capacity, the model takes into account the forecast impacts of the following **non-network solutions**:

- the continued transition from flat tariffs to solar sponge TOU tariffs for residential customers (assuming an accelerated smart meter rollout from 2025), which will continue to change the shape of the average residential load profile to have increased daytime load, as well as the introduction of export tariffs as a further price signal;
- our CER compliance program, which will increase hosting capacity by increasing compliance to AS4777 Volt-VAr settings, which reduces daytime voltage rise in high-solar areas;

- our demand flexibility program, which will facilitate additional shaping of daytime load to reduce export peaks; and
- our network visibility program, which allows for reduced curtailment under flexible exports through more accurate measurement of voltage.

The additional export capacity enabled via the above programs is factored into the base case, assuming these programs progress as planned. Because these effects have already been taken into consideration in forming the base case, the benefits attributed to the investment options in this business case are only the incremental benefits arising directly from those investments, so there is no double-counting. The benefits created by our other CER integration initiatives are considered separately in their respective business cases.

We also consider any synergies with our proposed asset replacement (repex) program in the base case. This ensures that the LV Planning Engine does not propose expenditure to replace or upgrade a transformer in a constrained area where the export constraint would be resolved through a planned replacement as part of our repex program.

The operation of the LV Planning Engine is described in detail in the associated methodology document[52].

5.1 The options considered

The following options are considered in this business case.

Table 2: Summary of options considered

Option	Description
The base case (Option 0)	The base case assumes no proactive investment in additional export capacity in the 2025-30 RCP. It includes only certain necessary costs associated with the ongoing provision of the export service such as maintenance of the systems that support flexible exports and Smarter Homes. Absent any new investment in export capacity, export constraints would be managed, where possible, by curtailment of customer solar output using flexible exports. In areas where this is not sufficient to maintain quality of supply, issues arising would be addressed reactively through our BAU LV maintenance process.
Option 1 – 90% LoS	Option 1 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 90% for 95% of customers.
Option 2 – 95% LoS	Option 2 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 95% for 95% of customers.
Option 3 – 98% LoS	Option 3 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 98% for 95% of customers.

[52] 5.7.9 - CER Integration Modelling Methodology

5.2 Options investigated but deemed non-credible

Through our stakeholder engagement program we also examined two other options:

- an investment plan that is driven only by the aim of optimising forecast market benefits as estimated using our variant of the CECV; and
- an investment plan with a target of an 85% service level.

We did not carry the first of these options through to our final options analysis because stakeholders expressed clearly and consistently that they preferred us to base our investment decisions on maintaining a level of service that customers wanted and were willing to pay for, and not purely on an estimation of future market benefits. This was the least popular option among stakeholders in our Focused Conversation workshops even though it had a lower level of investment, and hence lower estimated bill impact, than other options considered.

A key reason for this was that stakeholders took into consideration our intention to recover the costs of these investments from export customers only, via export tariffs. From that perspective, it was considered appropriate that we should be guided in our investment decisions by the preferences of those customers who would be paying for the investment, and not on our estimates of the potential benefits that would accrue to other customers.

Another reason stakeholders did not favour an investment strategy that was designed only to maximise net market benefits was that this would result in progressively more variation in export service levels across the network over time and would exclude significant cohorts of customers connected to parts of the network that have higher remediation costs, which stakeholders considered inequitable. Stakeholders placed a high value on the principles of fairness and equity and felt strongly that we should, within the bounds of practicality, seek to provide all export customers with broadly the same level of service performance, since all export customers pay for the investments we make in export capacity.

That said, stakeholders also understood that it would be inefficient to try to maintain the same service level for 100% of customers as the cost for some customers would be excessive. Stakeholders recognised that this is analogous to the situation today with other aspects of network performance such as reliability, where some customers are more poorly served than others because they are connected to network assets that have particularly high costs to upgrade relative to the benefits, e.g. because they are remote and / or serve very few customers.

Regarding the second option, the 85% service level, this was dropped following our Focused Conversation workshops because stakeholders were unanimous in rejecting this option. Stakeholders considered this was too low a grade of service, and preferred higher service levels even though the estimated bill impacts were higher.

We have included option 0 – the 'do nothing' case – as our base case in the options analysis below for the purpose of baselining costs and benefits to compare the other options. We do not consider this a credible option, however, as stakeholders rejected this option and have consistently expressed strong support for investment in additional export capacity to maintain export service levels.

Further detail on our stakeholder engagement process is included in section 6.

5.3 Analysis summary and recommended option

To inform the comparison of the options under consideration we undertook a quantitative 25-year NPV analysis of costs and benefits over the period from 2025 to 2050.

5.3.1 Quantified benefits

The analysis considers the following quantified benefits:

- future market value of avoided export curtailment, calculated in accordance with the AER's CECV methodology using the AER's June 2023 update of the CECV adjusted to incorporate an additional benefit factor representing the value of 'avoided generation capacity investment'[53]; and
- any residual (terminal) value of new capital assets at the end of the evaluation period.

5.3.2 Non-quantified benefits

We anticipate further benefits from the proposed program of work that we have not sought to quantify in the options analysis. These are common to all options, and these benefits generally increase with increased investment and the corresponding reduction in export curtailment. They include:

- customers' perceived value of exports and desire for a minimum level of export service performance. This was a material factor in our options consideration, but we have not sought to quantify it as a future benefit cashflow for the NPV analysis (although we considered quantitative evidence of customer willingness to pay for the export service obtained via our Customer Values Research survey[54];
- a reduction in specific risks identified in Appendix 0 that are included in the qualitative risk assessment shown below, but have not been quantified. These are:
  - risk of customer dissatisfaction, negative media and reputational harm due to solar customers experiencing levels of curtailment they find unacceptable;
  - cost of additional customer calls to our call centre if they are dissatisfied with the level of curtailment they are experiencing via their flexible export connection;
  - risk that excessive export curtailment discourages customers from installing larger systems in the 2025-30 RCP, leading to: 20-year purchasing decisions that may not be optimal in terms of the long-term return on investment for customers, an underutilisation of available roof space, all which may mean rooftop solar falls short of its potential to contribute to achieving a net-zero electricity system in South Australia; and
  - risk to security and quality of supply if our flexible exports system fails during a high-export period, causing un-curtailed reverse power flows that exceed network hosting capacity. The reliance on flexible exports to maintain quality and security of supply is higher for lower levels of capacity investment; and
- other economic benefits of higher levels of exports not captured in the CECV, e.g.:

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53 We engaged economic consultant Houston Kemp to quantify this benefit stream. Consideration of this benefit category is permitted in the AER's DER integration guidance note, noting that the AER's CECV has only attempted to quantify a subset of the likely reasonable benefit categories. Refer AER, *final customer export curtailment methodology*, June 2022, p.7. Refer 5.7.13 – Avoided generation investment report for further details on our approach.

54 See section 6.1

- value of carbon emissions reduction[55]. We may seek to quantify this benefit in future and we understand that this may be included in future revisions of the CECV, which would have the effect of increasing the CECV benefits included in this business case;
- increased VPP participation in markets and greater opportunity for residential batteries to inject higher levels of power to provide supply/demand balancing and frequency response services; and
- potential reduction in system losses due to increased co-location of consumption and generation.

5.3.3 Options assessment results

The table and figure below summarise the results of the comparison of options. Note that here the costs of option 0, the base case, have been subtracted from all options to provide a baseline for comparison of option 1, 2 and 3. Base case costs are summarised in section 5.4.1 below.

Table 3: Costs, benefits and risks of alternative options relative to the base case over the 25-year period, $m, $ June 2022 real. The Option 0 (Base Case) costs have been subtracted from all options.

Option	Costs		Benefits[56]			NPV[57]	Risk Level[58]	Ranking
	Capex[59]	Opex[60]	Capex	Opex	Customer			
Option 0 – Base Case	-	-	-	-	-	-	High	N/A[61]
Option 1 – 90% LoS	35.56	0.00	8.94	0.00	42.88	16.26	Medium	2
Option 2 – 95% LoS	42.80	0.00	9.82	0.00	51.92	18.94	Low	1
Option 3 – 98% LoS	67.52	0.00	16.86	0.00	54.74	4.07	Medium	3

55 Noting that reduced export curtailment contributes to the achievement of South Australia's targets for reducing greenhouse gas emissions, which aligns with recent changes to the National Energy Objective (NEO) (See https://www.aemc.gov.au/regulation/neo, accessed September 2023)

56 Represents the total capital and operating benefits, including any quantified risk reductions compared to the risk of Option 0 (base case), over the 25-year cash flow period from 1 July 2025 to 30 June 2050 expected across the organisation as a result of implementing the proposed option.

57 Net present value (NPV) of the proposal over 25-year period from 1 July 2025 to 30 June 2050, based on a discount rate of 4.05%.

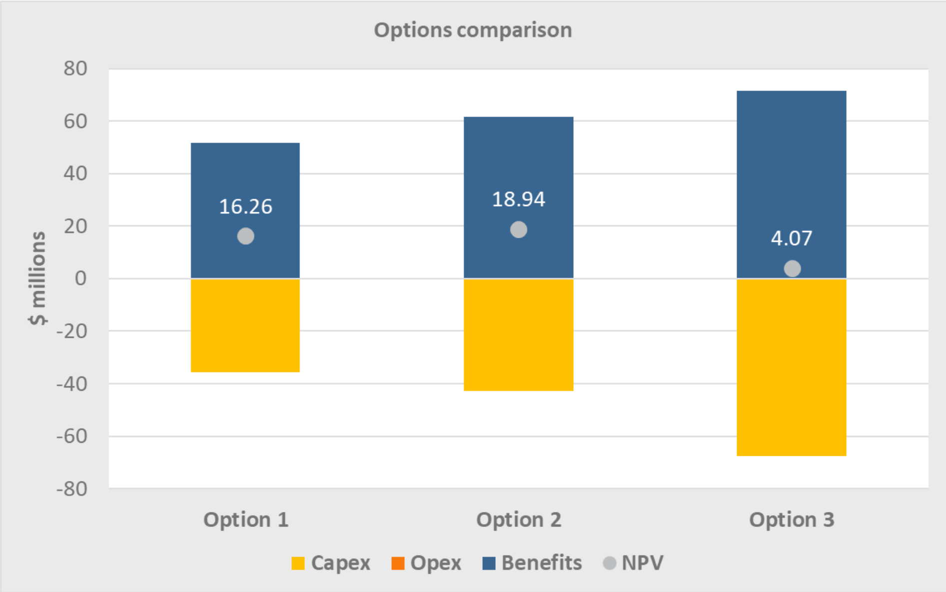
58 The overall risk level for each option after the proposed are implemented. Refer to Appendix B – risk assessment for details.

59 Represents the present value of total capex associated with the proposed option over the 25-year cash flow period from 1 July 2025 to 30 June 2050.

60 Represents the present value of the total opex increase associated with the proposed option above the current level of opex, over the 25-year cash flow period from 1 July 2025 to 30 June 2050.

61 The base case is not ranked as it is not considered to be a credible option.

Figure 9 – Options comparison summary



Assumptions

- Assumed CER uptake rates are based on AEMO's Electricity Statement of Opportunities (**ESOO**) 2022 forecasts for the Step Change ISP scenario, which AEMO considers as the central case. The sensitivity to other ISP scenarios is considered in section 5.4.
- The modelling assumes that we are undertaking our proposed CER compliance, demand flexibility, network visibility and repex programs in 2025-30. These programs will increase underlying hosting capacity through 2025-30 as well as increasing the level of CER activation and load shifting, reducing the need for export capacity augmentation.
- Other assumptions are documented in sections 9 and 10 below and in the methodology document[62].

5.3.4 Recommended option

Our recommended option is option 2, a capital investment program designed to maintain an export service performance level of at least 95% for 95% of customers. This option is recommended because:

- it best reflects the level of export service performance that our customers have indicated that they want and are willing to pay for:
  - it is the option chosen by stakeholders who deliberated on and voted on these options over a series of three half-day Focused Conversation workshops. During these deliberations stakeholders considered their expectations regarding future service levels, weighed against the estimated bill impact of each option;
  - it is aligned with the level of expenditure endorsed by our People's Panel in their deliberation on the totality of the recommendations made to them by the Focused Conversations; and
  - it aligns with preferences expressed in our Customer Values Research survey;
- it will deliver the highest positive market benefits of the options considered, when costs are netted against the forecast future market value of reduced curtailment using our modified version of the AER's CECV;
- in our view, taking into consideration stakeholder views as above and also our assessment of historical export service performance, it represents a prudent and efficient level of investment in new export

[62] 5.7.9 - CER Integration Modelling Methodology

capacity that, in combination with our flexible exports capability, will be sufficient to meet customer demand for the export service in the 2025-30 RCP under the range of possible future CER uptake rates examined in the sensitivity analysis set out in section 5.4 below; and

- while option 3 (a 98% service level) is the option that is most aligned with maintaining historical levels of export service performance and received significant support from stakeholders during our focused conversations, this option was not preferred because:
  - it would require a level of expenditure greater than that endorsed by our People's Panel; and
  - as shown in Figure 9 above, the cost/benefit ratio is significantly lower for this option than for options 1 or 2 due to the higher cost to maintain the higher level of service.

Further information on our stakeholder engagement is included in section 6 below.

The work program for our preferred option includes the following upgrade works to address emerging export constraints in the LV network between 2025 and 2030:

- deploy improved voltage regulation equipment (LDC) to 54 zone substations and integrate with ADMS;
- associated transformer re-tapping program to tap down 1,654 LV transformers to optimise LDC performance;
- upgrade 369 LV transformers to larger ones; and
- split 561 existing LV areas and install infill transformers.

Overall, this program will improve network voltage management and increase available export capacity in more than 2,600 LV transformer areas that would otherwise experience reduced levels of export service performance due to network congestion in the 2025-30 RCP.

5.4 Scenario and sensitivity analysis

The following sections further detail the options considered and the sensitivity analysis undertaken.

5.4.1 Option 0 – base case

5.4.1.1 Description

Option 0, the base case for this options analysis, assumes no proactive investment in additional export capacity in the 2025-30 RCP. Under this option, wherever possible, export constraints are managed by curtailment of customer solar output using flexible exports. In areas where this is insufficient to maintain quality of supply, issues arising will be addressed reactively through our BAU LV maintenance process.

Under this option service levels decline progressively through the 2025-30 period. We do not consider this to be a credible option as is would not effectively meet or manage customer demand for the export service in the 2025-30 RCP. This option has been consistently rejected by stakeholders throughout our stakeholder engagement process. It included here as a counterfactual to provide a baseline for comparison of the other options.

5.4.1.2 Costs

There is no proactive investment in additional export capacity under this option.

There are, however, necessary capital and operating costs associated with CER integration and the delivery of the export service that are not associated with the provision of extra export capacity for customers. These costs are unavoidable under any of the options here and hence have not been included in the options comparison – they are common to all options including the base case. These costs are required pursuant to clauses 6.5.7 and 6.5.6 of the NER in order to comply with applicable regulatory obligations as set out in section 4. They are summarised below.

- **Flexible exports systems maintenance and scaling costs**. This includes recurrent capex, minor enhancements, software licensing and maintenance costs for the core components of our flexible exports system shown in the architecture diagram in section 3.3.2 above. The flexible exports capability underpins our ability to efficiently manage expected demand for the export service regardless of the level of investment in new export capacity. We are committed to maintaining this capability in the 2025-30 RCP: under SA Government Smarter Homes regulations all new rooftop solar installations in South Australia are now required to support flexible exports, and this will be the standard connection method for rooftop solar in all areas of the network by the end of 2024. Total expenditure to maintain and scale the supporting systems in line with forecast growth in new solar connections is $2.40 million capex and $3.85 million opex over the 2025-30 RCP.
- **Smarter Homes and related CER supporting systems recurrent maintenance and scaling costs**. This includes recurrent capex, minor enhancements and maintenance costs for our Smarter Homes API and other systems developed in the 2020-25 RCP to support the activation of emergency backstop solar generation shedding in line with our obligations under the SA Government's 2020 Smarter Homes regulations and when directed to do so by AEMO. This includes systems to support our role as a Relevant Agent under the scheme, and our role in activating responses from third-party Relevant Agents[63]. It also includes related supporting systems such as our CER portal and systems to support monitoring and reporting export service performance in line with guidance in the AER's interim export limit guidance note[64]. Total expenditure in this area is $2.61 million capex.
- **Voltage regulators in the 66kV/33kV country sub-transmission network**. This is for 13 additional voltage regulators in regional locations to address forecast voltage rise at Electranet connection points. This work is required under all scenarios and options to maintain connection point voltage compliance in 2025-30. The cost of this work is $9.38 million capex.

These costs are summarised in the table below.

Table 4: Option 0 - Total Cost by Cost Type ($m June 2022 Real)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	2030-31	2031-32	2032-33	2033-34	2034-35	Total 2025-35
Capex	7.09	4.15	1.05	1.17	0.93	**14.40**	0.00	0.00	0.00	0.00	0.00	**14.40**
Opex	0.54	0.66	0.77	0.89	1.00	**3.85**	1.11	1.22	1.32	1.43	1.54	**10.46**
TOTAL COST	**7.63**	**4.81**	**1.82**	**2.06**	**1.93**	**18.24**	**1.11**	**1.22**	**1.32**	**1.43**	**1.54**	**24.86**

As noted above, as the above costs are common to all options, for the purpose of the options comparison, these costs are not included in the costs for options 1, 2 and 3.

63 Under the SA Government Smarter Homes regulations a Relevant Agent is the party responsible for activating a generation-shedding response (e.g. by signalling smart meters to disconnect solar inverters) when required during a system contingency event. SA Power Networks is responsible for issuing instructions to third-party Relevant Agents and monitoring the level of response achieved and uses specific systems and APIs to do this, and is also itself a Relevant Agent. See https://www.energymining.sa.gov.au/industry/modern-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes for further details of the Smarter Homes program.

64 AER, *Interim export limit guidance note – for consultation*, accessed at https://www.aer.gov.au/documents/draft-export-limit-interim-guidance-note-november-2023

5.4.1.3 Risks

Table 5: Option 0 - Risk assessment summary

Risk consequence category	Current risk level[65]	Risk cost[66]
Performance and Growth – Failure to deliver on strategic plan and growth objectives	High	Not quantified
Performance and Growth – Non-compliance with regulatory, legislative and/or other obligations	High	Included in CECV
Network – Failure to transport electricity from source to load	Low	Not quantified
Customers – Failure to deliver on customer expectations	High	Not quantified
Overall risk level	High	

5.4.1.4 Quantified benefits

As with costs, we have not included any quantified benefits attributable to the expenditure in the base case in the benefits for options 1, 2 or 3. The only benefits attributed to the options under consideration are the incremental benefits arising directly from the additional investments in new export capacity proposed in those options.

While we don't include the base case costs and benefits in the cost/benefit analysis of the options in this business case, we have estimated the CECV benefit attributable to the ongoing operation of the flexible exports capability. We can do this by considering the level of future export curtailment in the base case, i.e. if there is no investment in new export capacity. We have compared this future curtailment profile under our default assumption, which is that curtailment only occurs in the specific time intervals when export capacity is exceeded (enabled by the dynamic nature of flexible exports), with a counterfactual that assumes that the flexible exports capability is discontinued and all new export customers after 2025 receive a static export limit of 1.5 kW, which results in curtailment year-round. This analysis indicates that the expenditure in our base case is more than offset by the ongoing CECV benefits of maintaining the flexible exports capability, as shown in the summary table below.

Table 6: Costs and benefits attributable to base case expenditure over the 25-year period (not included in the comparison of options 1, 2 and 3). All figures are 2025 present value of 2025-2050 cashflows (discount rate of 4.05%), $m, $ June 2022 real.

Option	Costs		Benefits			NPV
	Capex	Opex	Capex	Opex	Customer	
Option 0 – Base Case	13.61	20.01	-	-	49.93	16.31

5.4.2 Option 1

5.4.2.1 Description

Option 1 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 90% for 95% of customers.

This option involves a program of LV network, HV network and substation upgrade works similar to that of the preferred option (option 2) as described in section 5.3.4 above, but reduced in scope commensurate with the lower target service level with respect to both the number of export-constrained LV transformer areas

65 The level of risk post current controls (ie after considering what we currently do to mitigate the risk).

66 Estimated cost of consequence(s) to SA Power Networks or its customers in an event this risk eventuates over the NPV analysis period.

to be upgraded and the nature of the remedial work (some lower-cost but lower-efficacy/shorter term solutions preferred compared to option 2).

5.4.2.2 Costs

Table 7: Option 1 - Costs by Cost Type ($m June 2022 Real)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	2030-31	2031-32	2032-33	2033-34	2034-35	Total 2025-35
Capex	14.64	7.64	5.06	4.64	6.46	**38.43**	0.00	0.00	0.00	0.00	0.00	**38.43**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	0.00	0.00	0.00	0.00	0.00	**0.00**
TOTAL COST	**14.64**	**7.64**	**5.06**	**4.64**	**6.46**	**38.43**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**38.43**

Further detail on costs is included in section 9 below.

5.4.2.3 Risks

Table 8: Option 1 – Risk assessment summary

Risk consequence category	Current risk level[67] (Option 0)	Residual risk level[68] (Option 1)	Risk cost[69]
Performance and Growth – Failure to deliver on strategic plan and growth objectives	High	Medium	Not quantified
Performance and Growth – Non-compliance with regulatory, legislative and/or other obligations	High	Medium	Included in CECV
Network – Failure to transport electricity from source to load	Low	Low	Not quantified
Customers – Failure to deliver on customer expectations	High	Medium	Not quantified
Overall risk level	High	Medium	

5.4.2.4 Quantified benefits

Table 9: Option 1 - Benefits by Expenditure Type ($m June 2022 Real)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	Total 2025-50
Capex	0.00	0.00	0.00	0.00	0.00	**0.00**	**21.42**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Customer	1.11	1.78	1.80	1.79	1.98	**8.46**	**73.79**
TOTAL	**1.11**	**1.78**	**1.80**	**1.79**	**1.98**	**8.46**	**95.21**

Further detail on benefits is included in section 9 below.

5.4.2.5 Unquantified benefits

Refer section 5.3.2. These unquantified benefits are expected to be slightly reduced under this option compared to option 2.

67 The level of risk post current controls (ie after considering what we currently do to mitigate the risk).

68 The residual level of risk under the proposed option.

69 Estimated cost of consequence(s) to SA Power Networks or its customers in an event this risk eventuates over the NPV analysis period.

5.4.3 Option 2

5.4.3.1 Description

Option 2 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 95% for 95% of customers.

This is the recommended option. It involves a program of LV network, HV network and substation upgrade works as described in section 5.3.4 above.

5.4.3.2 Costs

Table 10: Option 2 Total Cost by Cost Type ($m June 2022 Real)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	2030-31	2031-32	2032-33	2033-34	2034-35	Total 2025-35
Capex	17.33	4.52	11.48	6.10	6.99	**46.42**	0.00	0.00	0.00	0.00	0.00	**46.42**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	0.00	0.00	0.00	0.00	0.00	**0.00**
TOTAL COST	**17.33**	**4.52**	**11.48**	**6.10**	**6.99**	**46.42**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**46.42**

Further detail on costs is included in section 9 below.

5.4.3.3 Risks

Table 11: Option 2 Risk assessment summary

Risk consequence category	Current risk level (Option 0)	Residual risk level (Option 2)	Risk cost
Performance and Growth – Failure to deliver on strategic plan and growth objectives	High	Low	Not quantified
Performance and Growth – Non-compliance with regulatory, legislative and/or other obligations	High	Low	Included in CECV
Network – Failure to transport electricity from source to load	Low	Low	Not quantified
Customers – Failure to deliver on customer expectations	High	Low	Not quantified
Overall risk level	High	Low	

5.4.3.4 Quantified benefits

Table 12: Option 2 - Benefits by Expenditure Type ($m June 2022 Real)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	Total 2025-50
Capex	0.00	0.00	0.00	0.00	0.00	**0.00**	**22.76**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Customer	1.31	2.10	2.04	2.01	2.22	**9.68**	**90.51**
TOTAL	**1.31**	**2.10**	**2.04**	**2.01**	**2.22**	**9.68**	**113.28**

Further detail on benefits is included in section 9 below.

5.4.3.5 Unquantified benefits

Refer section 5.3.2.

5.4.4 Option 3

5.4.4.1 Description

Option 3 includes a capital investment program to add sufficient new export capacity to maintain an export service performance level of at least 98% for 95% of customers.

This option involves a program of LV network, HV network and substation upgrade works similar to that of the preferred option (option 2) as described in section 5.3.4 above, but increased in scope commensurate with the higher target service level with respect to both the number of export-constrained LV transformer areas to be upgraded and the nature of the remedial work (some higher-cost solutions required compared to option 2 to achieve the higher service level).

As noted in section 5.3.4 above, this option received considerable stakeholder support during our stakeholder engagement program because it is the option that most closely reflects current levels of export service, but is not our recommended option because it exceeds the level of service endorsed by our People's Panel.

5.4.4.2 Costs

Table 13: Option 3 - Total Cost by Cost Type ($m June 2022 Real)

Cost Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	2030-31	2031-32	2032-33	2033-34	2034-35	Total 2025-50
Capex	34.87	11.70	8.32	7.02	10.38	**72.28**	0.00	0.00	0.00	0.00	0.00	**72.28**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	0.00	0.00	0.00	0.00	0.00	**0.00**
TOTAL COST	**34.87**	**11.70**	**8.32**	**7.02**	**10.38**	**72.28**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**72.28**

Further detail on costs is included in section 9 below.

5.4.4.3 Risks

Table 14: Option 2 Risk assessment summary

Risk consequence category	Current risk level (Option 0)	Residual risk level (Option 2)	Risk cost
Performance and Growth – Failure to deliver on strategic plan and growth objectives	High	Medium	Not quantified
Performance and Growth – Non-compliance with regulatory, legislative and/or other obligations	High	Medium	Included in CECV
Network – Failure to transport electricity from source to load	Low	Low	Not quantified
Customers – Failure to deliver on customer expectations	High	Medium	Not quantified
Overall risk level	High	Medium	

5.4.4.4 Quantified benefits

Table 15: Option 3 - Benefits by Expenditure Type ($m June 2022 Real)

Benefit Type	2025-26	2026-27	2027-28	2028-29	2029-30	Total 2025 – 30	Total 2030-45
Capex	0.00	0.00	0.00	0.00	0.00	**0.00**	**40.04**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Customer	1.16	1.89	1.87	1.85	2.07	**8.83**	**97.44**
TOTAL	**1.16**	**1.89**	**1.87**	**1.85**	**2.07**	**8.83**	**137.48**

Further detail on benefits is included in section 9 below.

5.4.4.5 Unquantified benefits

Refer section 5.3.2. These unquantified benefits are expected to be slightly increased under this option compared to option 2.

5.4.5 Sensitivity analysis

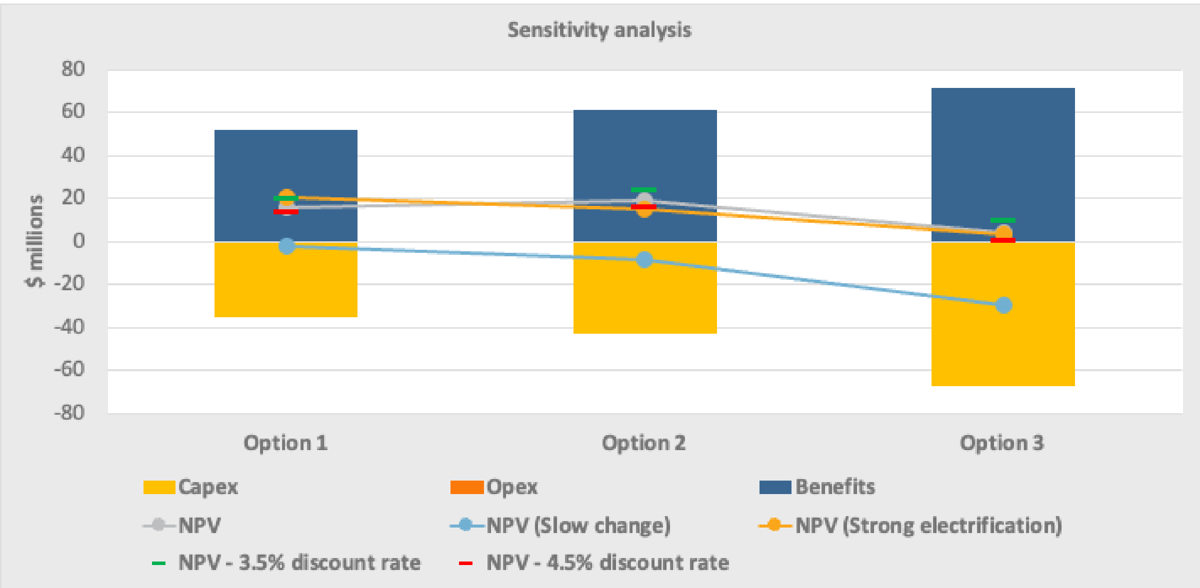
The level of expenditure required to maintain a given level of export service and the associated benefits due to avoided export curtailment depend on future CER uptake. For our modelling we relied on AEMO's ESOO 2022 forecasts for CER uptake in South Australia and we have used the 'Step change' ISP scenario as our central case. To test the robustness of our options analysis against a range of possible future CER uptake rates we have also modelled the outcome, in terms of CECV benefits, for our three options under the following sensitivity cases:

- a low-uptake / low-orchestration future scenario based on AEMO's 'Slow change' forecasts; and
- a high-uptake / high-orchestration scenario based on AEMO's 'Strong electrification' scenario.

In addition, we have assessed sensitivity to our assumed discount rate of 4.05% by repeating the NPV analysis using a lower discount rate of 3.5% and a higher one of 4.5%.

This analysis is summarized in the chart below.

Figure 10 – Sensitivity analysis



The sensitivity analysis suggests that our proposed investment options are robust to a higher-than-expected rate of CER uptake and orchestration, delivering broadly the same net benefits in the upper sensitivity case as in the central Step change scenario.

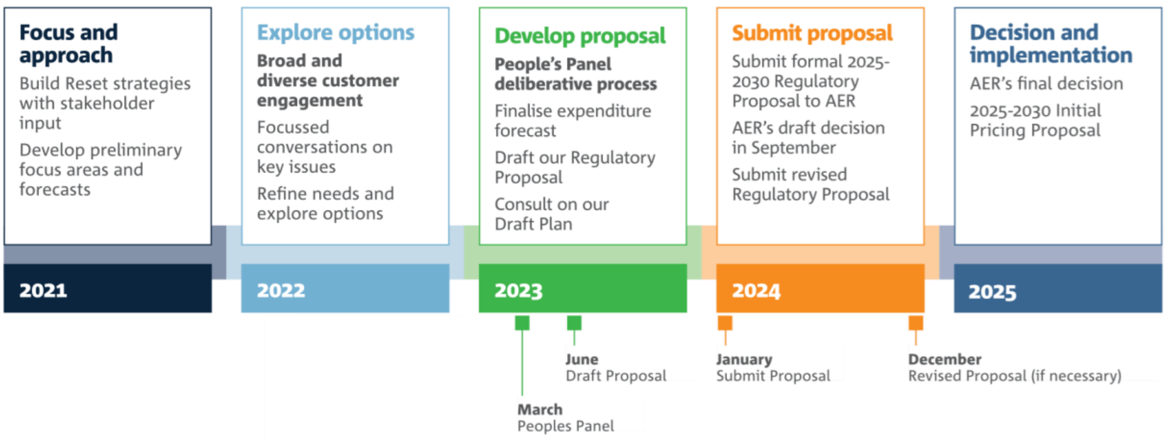
The modelling results indicate a slight negative NPV under the ESOO 2022 'Slow change' scenario in our preferred option (option 2), suggesting that our proposed investment plan may need to be modified during the next RCP if the rate of CER uptake were to decline significantly relative to forecasts. We consider that the likelihood of such a negative outcome eventuating is low, however, noting that in the more recent version of the ISP the 'Slow change' scenario has been retired as it is now considered unrealistic, while the Step change (now split into two variants) is still considered the most likely.

The analysis also indicates no material sensitivity to variations in the discount rate.

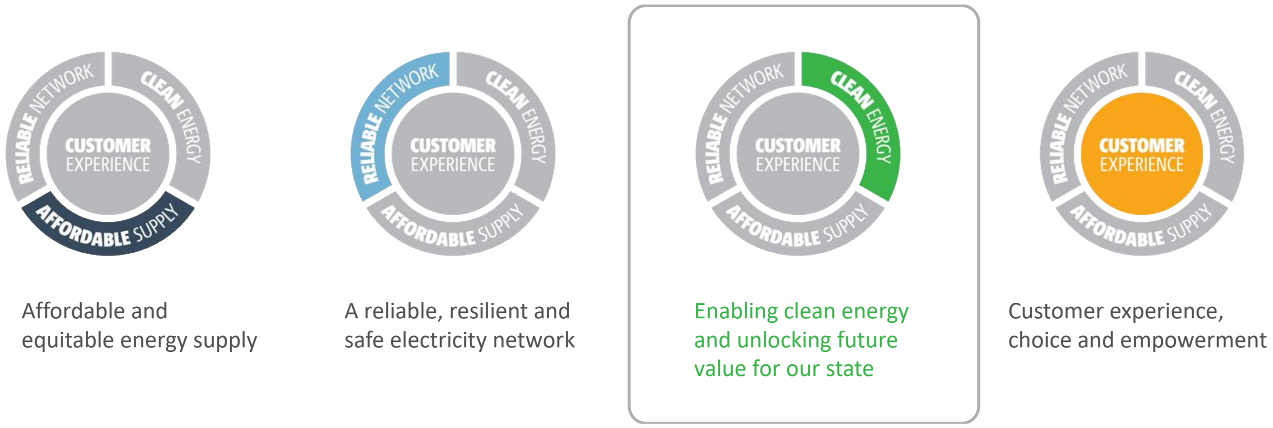
6 How the recommended option aligns with our engagement

6.1 Alignment to customer expectations

We undertook a comprehensive stakeholder engagement program for our 2025-30 Regulatory Proposal involving more than 700 participants across 56 workshops and other activities around the state since the program commenced in late 2021. The timeline is shown below.



Our engagement has been structured around the four key themes for our regulatory proposal shown below.



CER integration was the central topic of one of these themes, 'Enabling clean energy and unlocking future value for our state'. Consistent with our experience during our 2020-25 Regulatory Proposal process, it proved to be one of the areas of greatest interest to customers through all stages of the process.

Through this engagement process customers across all demographics indicated strong support for prudent investment in the distribution network to facilitate greater levels of rooftop solar, enable the transition to electric vehicles, and support the state government goal of reaching net 100% renewable electricity system by 2030, the end of our next RCP. This was again consistent with the views we heard during the development of our previous Regulatory Proposal; the South Australian community remains strongly supportive of the state's ongoing leadership in the energy transition and in investing to ensure our electricity system is ready for a 100% renewable future. This was a recurring theme through all phases of our engagement, as described below.

6.1.1 'Broad and diverse' workshops

Our formal community engagement began in early 2022 with a series of 12 community workshops around the state, facilitated by independent consultant *Think Human*, designed to seek the views of South Australians on what was most important to them for us to consider when planning for the 2025-30 RCP. This included general community workshops in the metropolitan area and in regional towns across the state, as well as six workshops targeting specific communities and demographics identified as facing barriers to participating in the regulatory reset process (deaf and hearing impaired, the indigenous community, youth and young adults, renters and the Italian and Afghan communities). The workshops were supplemented by our 'Talking Power' online engagement platform.

We heard the following recurring themes in the feedback we received through this process:

- customers strongly support the transition to renewable energy – but electricity needs to be reliable and affordable;
- the electricity industry is increasingly complex, and customers find it hard to navigate the choices available to them (different retail contracts, choices around adopting solar, batteries and so on); and
- equity is important; some sections of the community such as vulnerable customers and renters feel locked out of the opportunities afforded by the energy transition and we need to ensure that no-one is left behind.

6.1.2 Focused Conversation workshops

In the second half of 2022 we undertook a series of 44 Focused Conversation workshops to 'deep dive' on priority topics with interested and informed groups of stakeholders to further develop the detail of our proposal.

The options set out in this business case were developed and explored in depth with stakeholders through a series of three 'Energy Transition' Focused Conversation workshops. Participants included customers, community representatives from our Community Advisory Board (**CAB**), representatives from the South Australian business sector, local and state government, the solar industry, electricity retailers, renewable energy technology companies and the electric vehicle sector.

Through this process, participants deliberated on how we should approach our investment in export capacity and how much we should invest in the 2025-30 RCP, taking into consideration indicative bill impacts and service level outcomes based on preliminary modelling. Feedback from stakeholders was captured throughout, and, as far as possible, questions raised in the initial workshops were addressed in subsequent ones with additional information. At the end of the third workshop, 21 participants voted on the options.

The outcomes of this phase of engagement were:

- stakeholders did not want export service levels to decline. Solar customers are willing to tolerate a small amount of export curtailment so long as it is infrequent, but their clear expectation is that they should be able export all surplus energy from their system without being regularly limited;

- the 'minimal investment' base case received no votes, although it was the option that had no bill impact. All stakeholders supported some level of investment in additional export capacity;
- stakeholders felt overwhelmingly (20 votes to 1) that we should engage with customers to determine how much to invest based on the level of service customers want, rather than undertake a purely economic assessment based on potential market benefits to decide where and how much to invest;
- stakeholders considered a range of service levels from 85% to 98%, where 98% means that most solar customers can expect to have the output of their systems reduced no more than 2% of solar hours annually (<60 hours):
  - the majority (52%) favoured the highest service level (98%). Reasons included:
    - an understanding that costs would only be paid by solar customers, via an export tariff (hence not impact on non-solar and vulnerable customers); and
    - a recognition that the estimated residential bill impact would only represent a small proportion of the annual financial benefit solar customers receive from their systems, and is likely less material than other factors such as changing retailer feed-in tariffs;
  - a cohort (33%) favoured a lower service level, 90%, because it had a lower bill impact for residential solar customers, with the remainder favouring the service level in between, 95%; and
- while the 98% service level received the most votes, given the overall distribution of votes the option recommended as the final outcome of this process was the 95% service level.

6.1.3 Customer Values Research

During our stakeholder engagement program, we also engaged an independent consultant, Marsden Jacobs, to conduct a Customer Values Research survey study as another means to gain insights into customers' willingness to pay for specific elements of our proposal, including the question of export capacity investment.

This study used an online poll of a statistically representative sample of 1,400 South Australians and used a 'discrete choice' methodology that exposed respondents to a broad range of hypothetical bill impacts associated with different service levels in each area. A statistical analysis was then undertaken to estimate customers' overall average willingness to pay for different service outcomes.

The outcomes of this study aligned with the outcomes of the Focused Conversations, finding that the sampled customers were willing to pay at or above the forecast level of bill impact arising from the investments required to maintain a 95% service level for the export service[70].

6.1.4 Our People's Panel

The final stage in our formal stakeholder engagement process was our People's Panel, a panel of 51 South Australians from diverse backgrounds facilitated by consultant *DemocracyCo* in late 2022 and early 2023. Members of the People's Panel had not been involved in earlier stages of the stakeholder engagement process.

The role of the People's Panel was to consider our whole proposal (i.e. the total capex and opex, and price impact of the entire proposal) from a top-down perspective. The People's Panel deliberated on the totality of the specific recommendations made by the Focused Conversations and weighed the relative importance of expenditure in each area, taking into consideration overall bill impacts. Through this process some of the recommendations made in the Focused Conversations were rejected when considered in the context of the overall proposal, some were endorsed in full and others were modified.

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[70] Document 0.2 - Customer values research - Consultant Report

The People's Panel strongly endorsed the recommendations of our Focused Conversations in this area. 34 members of the original panel voted on this aspect of our proposal, and our proposed expenditure was endorsed by 33 votes to 1, one of the highest levels of consensus reached for any of the topics considered by the Panel.

6.1.5 Other customer research

Our approach and the 95% service level recommended via our stakeholder engagement process are consistent with the findings of two other studies we are aware of that have undertaken customer research in this area:

- the social analysis undertaken as part of the UNSW CANVAS study into export curtailment in South Australia[71] (and prior social studies cited in that study) found that:
  - the general view of the study participants was that some level of curtailment of exports is acceptable if it occurs on 'only a few occasions per year'. Customers have the expectation that they should be able to export their surplus solar energy and gain the benefit of their retail feed-in-tariff, and do not expect to be curtailed frequently; and
  - study participants understood that there would be some unevenness in the distribution of the effects of curtailment, but generally felt that 'fairness' in the application of curtailment and the allocation of network capacity is important.
- customer research[72] conducted by Newgate during our previous reset process, which found that:
  - 74% of customers felt positively about "SA Power Networks spending money on its network to enable more solar in South Australia" with just 4% feeling negative about this;
  - most (54%) of respondents supported the use of flexible exports and occasional curtailment as a more efficient approach to managing network capacity than relieving all export constraints through augmentation; but
  - there was also considerable support for a 'comprehensive upgrade' option that involved considerable network augmentation, with 33% of respondents preferring this option even though it had the highest bill impact of those presented. These customers expressed a common sentiment that we should be investing in 'fixing it properly' and 'future proofing the network' to support continued growth of solar for the long term.

6.2 Alignment with the views of CER industry stakeholders

We engaged on our proposed approach to CER integration with our DER Integration Working Group (**DERIWG**). This group was established in 2018 following a recommendation by the AER's Consumer Challenge Panel (**CCP**) during our previous regulatory proposal process and proved to be such a valuable and effective forum that we have continued to convene it on a quarterly basis ever since. Our consultation with this group has helped guide and shape our approach to CER integration, flexible exports, export service levels and pricing over the last five years.

The group comprises a mix of senior CER industry stakeholders from across Australia as well as senior representatives from Energy Consumers Australia (**ECA**), the Total Environment Centre (**TEC**), the Clean Energy Council, (**CEC**) the Electric Vehicle Council (**EVC**), the South Australian Government and AEMO. It is a

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71 UNSW Sydney, *Curtailment and Network Voltage Analysis Study (CANVAS), Final Report 2021*, project undertaken as part of the RACE for 2030 CRC.

72 Newgate Research, *Community attitudes towards solar*, supporting document 0.16 to SA Power Networks' 2020-2025 Regulatory Proposal, accessed at https://www.aer.gov.au/documents/sapn-016-newgate-research-community-attitudes-towards-solar-december-2018.

highly engaged and informed stakeholder group that brings a national perspective, a diversity of viewpoints, and broad and deep knowledge of regulatory, industry and customer issues around the energy transition.

As well as regular online meetings, we hosted a half-day workshop in October 2022 in Melbourne with the DERIWG specifically to canvas key aspects of our regulatory proposal. The workshop explored the question of how we should apply market benefit measures based on the CECV in combination with customer preferences to establish the right level of investment in export capacity, the relative risks of over- or under-investment in export capacity in the 2025-30 period, and the pathway to transition to export tariffs.

Stakeholder views expressed in this workshop were generally well aligned with our proposed approach:

- stakeholders strongly favoured a holistic approach to CER integration that sought to maximise the opportunity for market-based solutions to address excess solar production – e.g. price signals, load flexibility and retailer-led solar management offers – in order to reduce the need for extra network capacity;
- that said, stakeholders felt strongly that some network investment in export capacity would be very important in the 2025-30 period;
- the risk of under-investment in the network in the 2025-30 period was seen as a greater concern than the risk of over-investment, on the basis that:
  - the pace of change and rate of solar uptake have consistently exceeded expectations in recent years and so DERIWG members felt that AEMO’s forecasts are more likely to under-estimate the need for export capacity than to over-estimate it;
  - CER uptake was expected to continue to grow beyond 2030, so any excess export capacity would likely be required in future; and
  - the 2025-30 period was seen as a critical period in achieving the levels of renewable energy required to meet net-zero goals. There was a concern that if network constraints became a disincentive for customers to install larger systems during the 2025-30 period then we might ‘waste’ roof space and may not achieve the full potential of rooftop solar in the future decarbonised energy mix, noting that for most customers choosing the size of their system may be a one-in-20-year decision; and
- stakeholders favoured a ‘user pays’ approach to the export service and supported the introduction of export tariffs. That said, most stakeholder considered that broader market benefits should be taken into consideration in determining the level of network investment in export capacity, although some expressed concerns with the CECV as a single measure.

6.3 Feedback on our Draft Proposal

Since conducting the People’s Panel process, we published a Draft Proposal in August 2023 to play back how we have given effect to customer recommendations, to confirm that those recommendations remain valid given continued cost of living pressures and to obtain further input to refine our Regulatory Proposal.

Submissions received on our Draft Proposal suggest that the recommendations of the People’s panel remain valid with respect to the CER integration program, noting that:

- members of the People’s Panel affirmed that their recommendations, including in respect of property expenditure as set out in this business case, remain current;[73]

73 DemocracyCo, *Submission: SA Power Networks Draft Regulatory Proposal 2025-30*, 30 August 2023.

- some parties such as the SA Council of Social Servicess (**SACOSS**)[74] and the Department of Energy and Mining [75] generally urged further consideration of the overall magnitude of our forecast capital expenditure in totality. SACOSS also said that any support it has for the sevice level proposed in this business case is contingent on export tariffs being introduced to ensure that non-solar customers do not pay for this service;
- the Energy and Water Ombudsman of South Australia (**EWOSA**) noted that it supports maintining export service levels for solar customesr at 95%, with export tariffs to recover the cost of enabling this service level – with view to enabling clean energy and effectively manage CER;[76] and
- the majority of survey respondants replied that they were either very satisfied and somewhat satisfied with the CER integration program.

7 Alignment with national policy and AER guidance

We continue to engage actively on energy policy, particularly in relation to CER integration, with industry leaders and policy makers at state and federal level. This includes ongoing engagement with the South Australian Government, the market bodies, the Energy Security Board (**ESB**), particularly in the DER workstream of the ESB's Post-2025 Market Review, other DNSPs through Energy Networks Australia (**ENA**), industry working groups and other relevant national bodies such as ARENA's Distributed Energy Integration Program (**DEIP**). We consider that our approach to CER integration and the management of export capacity is aligned with broader policy direction at a state and national level and will support the level of CER participation envisaged for the post-2025 market.

We were an active participant in the 2019 DEIP Network Access and Pricing review and a rule change proponent in the subsequent process that led to the *Access, pricing and incentive arrangements for distributed energy resources* rule change in 2021, which has established the foundations in the NER for DNSP investment in export capacity, the establishment of export service levels, and the recovery of costs via export tariffs.

We have actively engaged with the subsequent regulatory processes to contribute to the development of the AER's guidelines regarding best practice for CER integration. Our approach has been informed by, and aligns with, the following AER documents:

Table 16: Alignment with AER guidance

AER document	Primary reference in our regulatory proposal
DER Integration Expenditure Guidance Note	5.7.15 CER integration strategy, including Appendix A
CECV methodology	This business case, including Appendix 0
Interim export limit guidance note	5.7.15 CER integration strategy, Appendix B

[74] SACOSS, *South Australian Council of Social Service Submission on SA Power Networks' 2025-30 Draft Regulatory Proposal*, September 2023.

[75] DEM, *South Australian Department of Energy and Mining* – Submission, October 2023.

[76] EWOSA, *Submission to SA Power Networks: Draft Regulatory Proposal 2025-30*, pp.2-3.

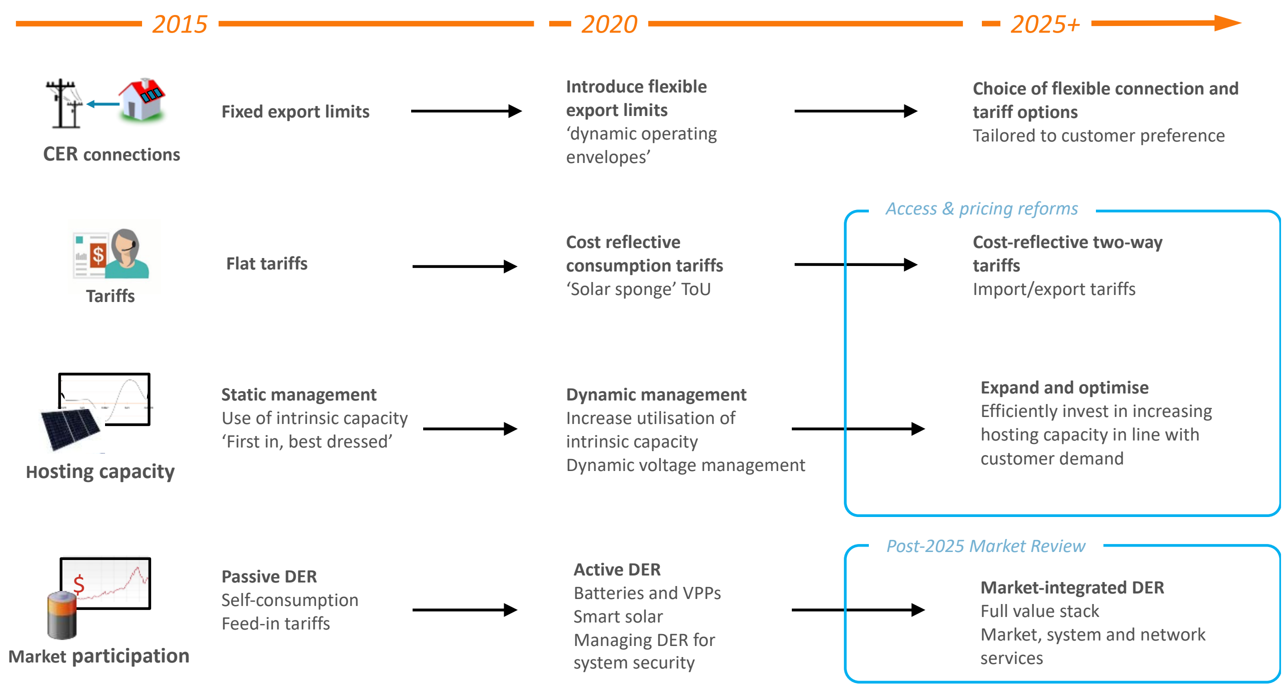
8 Alignment with our vision and strategy

As described in section 3.3 above, our approach is part of a comprehensive, integrated long-term strategy that aims to manage the changing role of the distribution network through an efficient combination of price signals (tariffs), network-side and demand-side (non-network, market-based) solutions.

Our 2025-30 Regulatory Proposal represents the next phase in a journey that began with our 2017 Future Network Strategy[77] and builds on the successful execution of the plans set out in our 2020-25 Regulatory Proposal[78] and our Distributed Energy Transition Roadmap[79], shown in Appendix 0.

As noted in section 3.3, our focus in 2020-25 has been on putting in place key foundations to enable us to manage immediate risks to quality and security of supply at times of minimum demand, and to maximise utilisation of the export capacity we have – cost-reflective tariffs, beginning the process of shifting of hot water loads to the daytime, improved voltage management, Smarter Homes and, most importantly, flexible exports.

As we look towards the crucial second half of the decade on South Australia's pathway to a net zero carbon electricity system by 2030, our 2025-30 Regulatory Proposal builds on these foundations and takes the next step in our long-term plan for solar integration, progressively and prudently adding export capacity to maintain export service levels in line with growth in demand – a step made possible by the 2021 *Access, pricing and incentive arrangements for distributed energy resources* rule change to which we were key contributors. This planned progression is summarised in the figure below.



77 SA Power Networks, *Future Network Strategy 2017-2030*, supporting document 5.17 to our 2020-25 regulatory proposal, accessed at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal. Updated in 2020 for our *Network Strategy 2020-2030*.

78 SA Power Networks, *2020-25 Regulatory Proposal, An overview for South Australian electricity customers*, accessed at https://www.aer.gov.au/system/files/SAPN%20-%20%20Electricity%20Distribution%20Proposal%202020-2025%20-Overview%20-%20January%202019_0.pdf.

79 SA Power Networks, *Distributed Energy Transition Roadmap 2020-2025*, accessed via https://www.sapowernetworks.com.au/future-energy/.

9 Reasonableness of cost and benefit estimates

Our methodologies for estimating costs and benefits are described in detail in the associated methodology document[80]. The tables below provide a summary.

9.1 Costs

Cost item	Basis of estimate
LV network augmentation capital costs	Our LV Planning Engine seeks to identify, in each year, the most efficient set of network investments required to alleviate forecast constraints. It chooses from a set of well-known network augmentation projects such as transformer upgrades, infills, transformer re-tapping, installing voltage regulators, and so on. The input cost for each of these remediations has been derived from historical actual costs from a sample of 600 previous similar remediation projects undertaken between 2017 and 2022, escalated to $2022.
Repex program overlap	The LV Planning Engine takes into consideration the set of LV transformers that are scheduled to be replaced in the 2025-30 period as part of our repex program, so that the hosting capacity benefits of these repex replacements are already included in our base case, and there is no double counting. A constrained LV transformer will not be included in the investment plan proposed by the LV planning Engine if it is already included in the repex program and if the repex replacement addresses the export constraint.
Flexible exports recurrent maintenance and scaling and Smarter Homes system costs	CAPEX and OPEX costs for the continued scaling and operation of the IT systems that support flexible exports and Smarter Homes have been estimated based on historical development and maintenance costs for those components developed in-house, escalated to $2022, and current vendor licencing costs for 3rd party components, with growth forecasts derived from our primary AEMO input forecasts for CER growth.
HV network (sub-transmission) voltage regulators	Augex costs for 66kV and 33kV voltage regulators in the sub-transmission network have been estimated using standard network planning estimation tools and 2022 asset costs and labour rates.

80 5.7.9 - CER Integration Modelling Methodology

9.2 Benefits

Benefit item	Basis of estimate
Value of avoided export curtailment (CECV)	The value of avoided export curtailment is calculated in accordance with the AER's CECV Methodology using the AER's published CECV values with the addition of a value component reflective of the value of deferred generation capacity investment, estimated using a methodology developed by Houston Kemp based on our forecast curtailment alleviation profiles for South Australia. Details of the methodology are provided in the separate consultant report[81].
Benefits arising from other work programs	Our 2025-30 CER integration strategy[82] includes three related work programs in addition to the one described in this business case: ▪ our CER compliance program, which will help increase underlying hosting capacity by increasing compliance of installed CER to AS4777 settings such as Volt/VAr; ▪ our demand flexibility program which aims to facilitate shifting and shaping of loads to better match daytime solar production, increasing self-consumption and reducing the need for export capacity; and ▪ our network visibility program, which uses smart meter data to improve the accuracy of our hosting capacity model, enabling greater customer access to capacity. All these programs reduce the future level of export curtailment and hence reduce the need for export capacity augmentation in the 2025-30 period. For the purpose of the cost/benefit analysis in this business case, the impacts of all of these are factored into the base case for our modelling. The ongoing impact of cost-reflective tariffs are also taken into consideration in the base case, assuming that tariff transition proceeds at a speed commensurate with the AEMC's proposed accelerated smart meter rollout through 2025-30. This means that the CECV benefits for options in this business case are only the incremental benefits directly attributable to the proposed capacity augmentation work, assuming that our other programs proceed as planned and after tariff impacts have been accounted for. The CECV benefits attributable to our other CER integration programs are included in their respective business cases.
Asset terminal values	The cost/benefit analysis in this business case uses a rolling 20 year NPV to calculate CECV benefits for investments made in each year in the 2025-30 RCP. For assets whose asset life exceeds the 20 year period, CECV benefits are only accrued for 20 years, and an asset terminal value is incorporated as a benefit in year 20 to reflect the remaining value of the asset at the end of the evaluation period.

[81] 5.7.13 - Avoided Generation Investment Report - Consultant Report

[82] 5.7.15 - CER Integration Strategy

10 Reasonableness of input assumptions

Our key input assumptions are described in detail in the associated methodology document. The table below provides a summary.

Table 17: Basis of key input assumptions

Input assumption	Basis
CER uptake forecasts - **Solar** - **Battery** - **EV** **Peak demand growth forecasts**	Derived from AEMO's August 2022 ESOO forecasts for South Australia based on the ISP Step Change scenario as the central case, with other ISP scenarios used as sensitivities. State-wide input forecasts are broken down to postcode level using a model developed by consultant Blunomy (formerly Enea) that takes into account demographic factors and local saturation factors (e.g. limits of roof space for new solar). Postcode-level forecasts are then re-aggregated to produce forecasts at individual assets, taking into consideration that some assets include customers from more than one post code, and customers in some postcodes are split between different assets. AEMO EV forecasts have been cross-checked against an independent bottom-up forecast of EV growth in SA developed by consultant Evenergi.
Load profiles – commercial and residential customer underlying load	Derived from an analysis of historical customer smart meter data and segregated into different load profiles for different temperature bands. These input profiles take into consideration the difference between customers on flat tariffs and those on Time-of-Use tariffs. Forecast smart meter uptake rates are used to forecast the uptake of Time-of-Use tariffs, assuming that the AEMC's proposed accelerated smart meter rollout proceeds as intended.
Load profiles – hot water loads	Hot water load profiles are derived from historical customer smart meter data. Two separate profiles are used, reflective of customers on traditional overnight off-peak tariff and those on the current 'solar sponge' time-of-use tariff. The extent of tariff response for the latter is estimated based on an analysis of the progress of retailer load-shifting since these tariffs were introduced, extrapolated to an estimated level of load shifting by 2025. Forecast smart meter uptake rates are used to forecast the transition from overnight to 'solar sponge' hot water profiles.
Load profiles – batteries	Derived from actual data from battery customers in South Australia, including simple 'solar shifting' behaviour and VPP customers.
Load profiles – EV charging	EV charging profiles were developed by EV consultant Evenergi, taking into account data from recent studies of EV charging and expected levels of time-of-use tariff response in South Australia
LV transformer hosting capacity	Estimated via an extension of the methodology developed for our 2020-25 reset proposal. Individual per-transformer estimates using a combination of • the original PowerFactory modelling of sample LV circuits of different types used to produce hosting capacity estimates on a per-category basis for our 2020-25 proposal, adjusted to account for changes in the network since the original modelling, e.g. where LDC has been deployed; • actual measured hosting capacity for those transformers where we have sufficient smart meter data to determine this; and • estimation based on extrapolation from available smart meter data from similar transformers, for those transformers where there is sufficient data to enable this.

Appendix A – Risk assessment

				Current risk (Option 0)			Residual risk (Option 1)			Residual risk (Option 2)			Residual risk (Option 3)		
ID	Risk scenario	Consequence description	Consequence category	Consequence	Likelihood	Risk Level	Consequence	Likelihood	Risk Level	Consequence	Likelihood	Risk Level	Consequence	Likelihood	Risk Level
1	Under-investment in export capacity leads to a sustained period of increasingly frequent and severe curtailment of exports for customers. This could arise if we underestimate future CER growth, or if we set a target service level for the export service that is too low.	Failure to meet our strategic goal to support South Australia's transition to net-zero by 2030 as network constraints prevent solar energy from being redistributed and put to productive use. This increases reliance on fossil fuels in the near term, impeding the transition to net-zero. It also discourages customer from installing larger PV systems, resulting in under-utilisation of roof-space and a failure to realise the full potential of rooftop solar in the long term	**Performance and Growth** – Failure to deliver on strategic plan and growth objectives	3	5	High	3	3	Medium	3	2	Low	3	2	Low
		Failure to meet our obligations made clear under the 'Access, pricing and incentive arrangements for DER' rule change to meet or manage customer demand for the export service.	**Performance and Growth** – Non-compliance with regulatory, legislative and/or other obligations	3	5	High	3	3	Medium	3	2	Low	3	2	Low
		Failure to meet customer expectations and failure to	**Customers** – Failure to deliver on	3	5	High	3	3	Medium	3	2	Low	3	1	Low

		deliver on the commitments made in our reset stakeholder engagement leads to widespread customer dissatisfaction, negative state and national media coverage, reputational harm, loss of trust, breakdown of the strong and collaborative relationship with the solar industry that we have invested in building in this period and potentially political intervention.	customer expectations												
2	Over-investment in export capacity leads to unnecessary bill impacts and stranded assets. This could arise if we overestimate future CER growth, or if we set a target service level for the export service that is too high. We examined this risk in a workshop with industry stakeholders in our DER Integration Working Group, who considered that since demand for the export service was expected to continue to grow beyond 2030,	Failure to meet our strategic goals to keep network costs down and support clean, reliable and <u>affordable</u> energy in South Australia and to increase asset 44ocalized44n and network efficiency over time.	**Performance and Growth** – Failure to deliver on strategic plan and growth objectives	3	1	Low	3	2	Low	3	2	Low	3	3	Medium
		Network expenditure in 2025-30 exceeds the minimum required by a prudent and efficient network operator to meet or manage demand for the export service.	**Performance and Growth** – Non-compliance with regulatory, legislative and/or other obligations	3	1	Low	3	2	Low	3	2	Low	3	3	Medium
		Customers are highly satisfied with export service levels, but face a higher bill impact through their export tariff than the expectations set through our stakeholder engagement program.	**Customers** – Failure to deliver on customer expectations	3	1	Low	3	2	Low	3	2	Low	3	3	Medium

	the consequence of overinvestment in the 2025-30 period was likely to be limited to the cost of bringing forward investment that would otherwise be required in 2030-35.															
3	Failure of flexible exports systems causes a failure to curtail exports to within network capacity at a high-export time, leading to widespread overvoltage issues and some customer outages due to fuses operating in the LV network from excessive reverse currents. Our approach to CER integration relies on flexible exports working correctly. This risk has been examined in depth in the national CSIP-AUS working group and strong mitigation measures are	Flexible exports is at the core of our strategic approach to CER integration; a serious failure would be a material setback to the delivery of our long-term strategies and also undermine confidence in the approach across the NEM, potentially leading to less optimal outcomes (e.g. over-building network capacity).	**Performance and Growth** – Failure to deliver on strategic plan and growth objectives	4	1	Low	4	1	Low	3	1	Low	3	1	Low
		Failure to meet regulatory obligations to maintain quality and security of supply	**Performance and Growth** – Non-compliance with regulatory, legislative and/or other obligations	3	1	Low	3	1	Low	2	1	Minimal	2	1	Minimal
		Potential 45ocalized outages due to fuse operations in the LV network from excess reverse power flows, also impacting the consumption service.	**Network** – Failure to transport electricity from source to load	3	1	Low	3	1	Low	2	1	Minimal	2	1	Minimal
		Potential for widespread customer dissatisfaction, negative media coverage,	**Customers** – Failure to deliver on	3	1	Low	3	1	Low	2	1	Minimal	2	1	Minimal

incorporated into the standard including fallback to safe export levels on loss of comms and strong cyber security. Our compliance program also serves to help mitigate this risk.	reputational harm and loss of trust.	customer expectations				
		Overall Risk Level[83]	High	Medium	Low	Medium

[83] For each option, the overall risk level is the highest of the individual risk levels.

Appendix B – Measuring export service performance

To engage with customers on the level of export service they receive from the network, and the level of service they want in future and are willing to pay for, we need a means to describe export service performance in a way that customers can easily understand and that we can readily measure and forecast.

In 2021, the University of Technology Sydney (**UTS**) commenced a project under the Reliable Affordable Clean Energy (**RACE**) for 2030 Cooperative Research Centre (**CRC**) to examine this issue, convening a consortium of electricity sector partners to explore different ways in which DNSPs could measure and express export service performance. SA Power Networks were partners in this project alongside Essential Energy, Solar Analytics, ECA, and the AER. Ideas developed through the project were tested and reviewed through a broader project Industry Reference Group that also included representatives from ENA, the CEC the AEMC, Horizon Power, the ARENA and the state governments of NSW, Victoria, Queensland and South Australia. Industry representatives from SA Power Networks' Solar Industry Reference Group (**SIRG**) and DERIWG also provided input to the project.

The UTS study generated and examined a list of 28 possible metrics for expressing export service performance. These were considered from the perspectives of three areas of application: **customer communication**; **regulatory compliance** (including suitability for use in future incentive schemes) and **grid operation and planning**. Proposed metrics were assessed against 20 criteria such as practicality, measurability, relevance and understandability, with real network data used where possible to explore how practical it was to calculate each one.

The outcome of the project was a shortlist of four final measures of export service performance:

- **volume of curtailment (#27)** – the volume of export energy in kWh that customers could have exported to the market that was curtailed due to network constraints;
- **total utilised DER generation (#5)** – the total amount of energy able to be produced by customer energy resources, including energy exported to the grid and energy consumed behind the meter;
- **duration of full export access (#10)** – the annual percentage of time customers experience unconstrained access to export up to the maximum capacity of their equipment (or the maximum export limit in their connection agreement); and
- **export service levels achieved (#28)** – the level of compliance a DNSP achieves with the export service levels stated in its customer connection agreements.

The first of these, **volume of curtailment (#27)**, is the measure calculated by our LV Planning Engine to forecast future benefits using the CECV[84].

Our preferred customer-facing measure of export service performance is based on the third measure recommended by the UTS study, **duration of full export access (#10).** We calculate this as follows[85]:

$$Export\ Level\ of\ Service = \frac{number\ of\ hours\ where\ exports\ were\ constrained}{total\ number\ of\ daylight\ hours}\quad (annual\ \%)$$

[84] The benefit of an investment in increased capacity being the difference between the forecast future volume of curtailment without the investment and the volume of curtailment with the investment, this difference also being referred to as the *alleviation profile*.

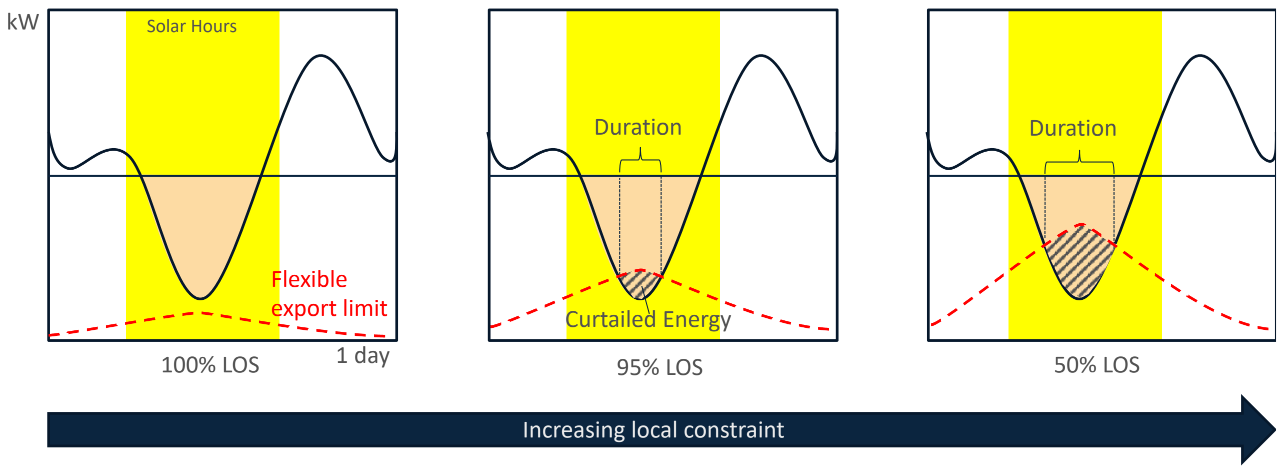
[85] In practice this is calculated and forecast at a granularity of half-hourly intervals today

This is the measure that we use in communicating with customers in relation to the service levels they receive through flexible exports, and the one we have used in our stakeholder engagement and in this business case.

Note that we express export service performance as the percentage of *solar* hours through the year when a customer receives un-constrained access to export to the network, rather than the percentage of *all* hours in the year. This recognises that export service performance is primarily a concern for solar customers and export constraints are highly unlikely to arise outside of solar hours[86]. For a solar customer, including un-constrained night-time hours, when the customer could not have exported in any event, in the calculation of a service level like '95% availability of full access' could be misleading and paint an overly-optimistic picture of the actual service level the customer experiences.

This export service performance metric is illustrated in Figure 11 below

Figure 11: Duration of full export access: our preferred Level-of-Service (LOS) measure for export service performance



Full details of the UTS study can be found in the associated project report, *Measuring and communicating network export service quality*, published in February 2023[87].

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86 Noting that those customers with batteries can, in theory, export at any time of day or night.

87 Langham, E.L., Guerrero, J., Nagrath, K. and Roche, D. (2022). *Measuring and communicating network export service quality*. Prepared for RACE for 2030, February 2023.

Appendix C – application of the CECV

How we use the CECV

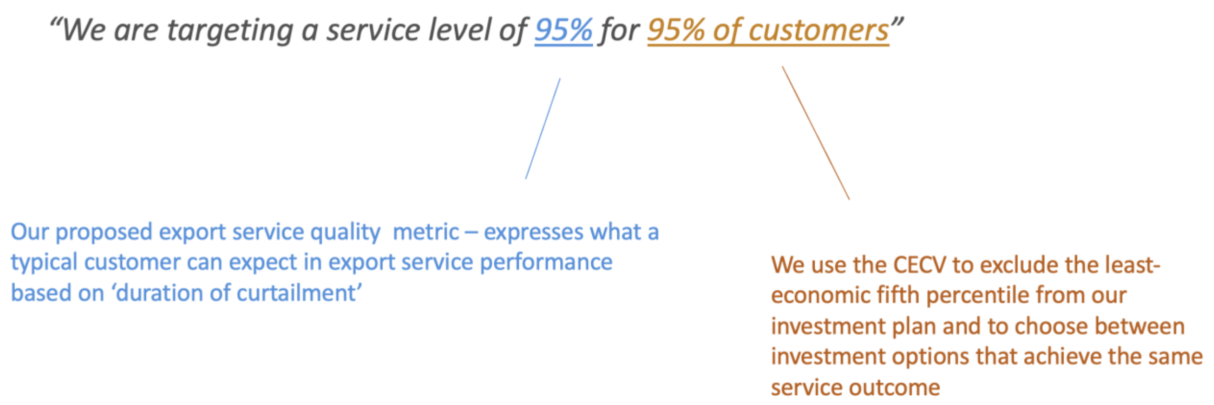
The cost of our export capacity investment program will be recovered only from those customers who use the export service, via an export tariff. Hence the primary goal of our CER integration investment plan is to make an efficient series of network capacity investments that is sufficient to maintain export service performance through the 2025-30 RCP at the level that export customers have told us they want and are willing to pay for. This is a service level of at least 95% full export access for at least 95% of customers.

To the extent we have choices in the specific investments that we make to achieve our export service performance target we aim to choose those investments that deliver the most consequential value to all customers (not just export customers). To do this we consider the future market value of alleviated export curtailment associated with each option, estimated using our variant of the CECV. This provides a metric we can use to:

- exclude the least-economic investments (noting that our goal to maintain the target service level for at least 95% of customers recognises that for certain network areas it may be infeasible or cost-prohibitive to add the necessary export capacity); and
- choose between alternatives that achieve the same service outcome (e.g. a more expensive solution may be preferred over a lower-cost one even though both would be sufficient to maintain the target service level until 2030 if the more expensive one delivers a better long-term economic outcome for customers).

This approach is illustrated in Figure 12 below.

Figure 12: Use of CECV when investing to maintain a target service level



Our LV Planning Engine forecasts future export curtailment in each LV transformer area in each individual 30-minute interval from 2025 to 2050, and so our methodology use the complete 30-minute CECV table provided by the AER, supplemented with the additional value metric developed by Houston Kemp, representing the value of avoided generation capacity investment[88], which is also expressed as a 30-minute value stream.

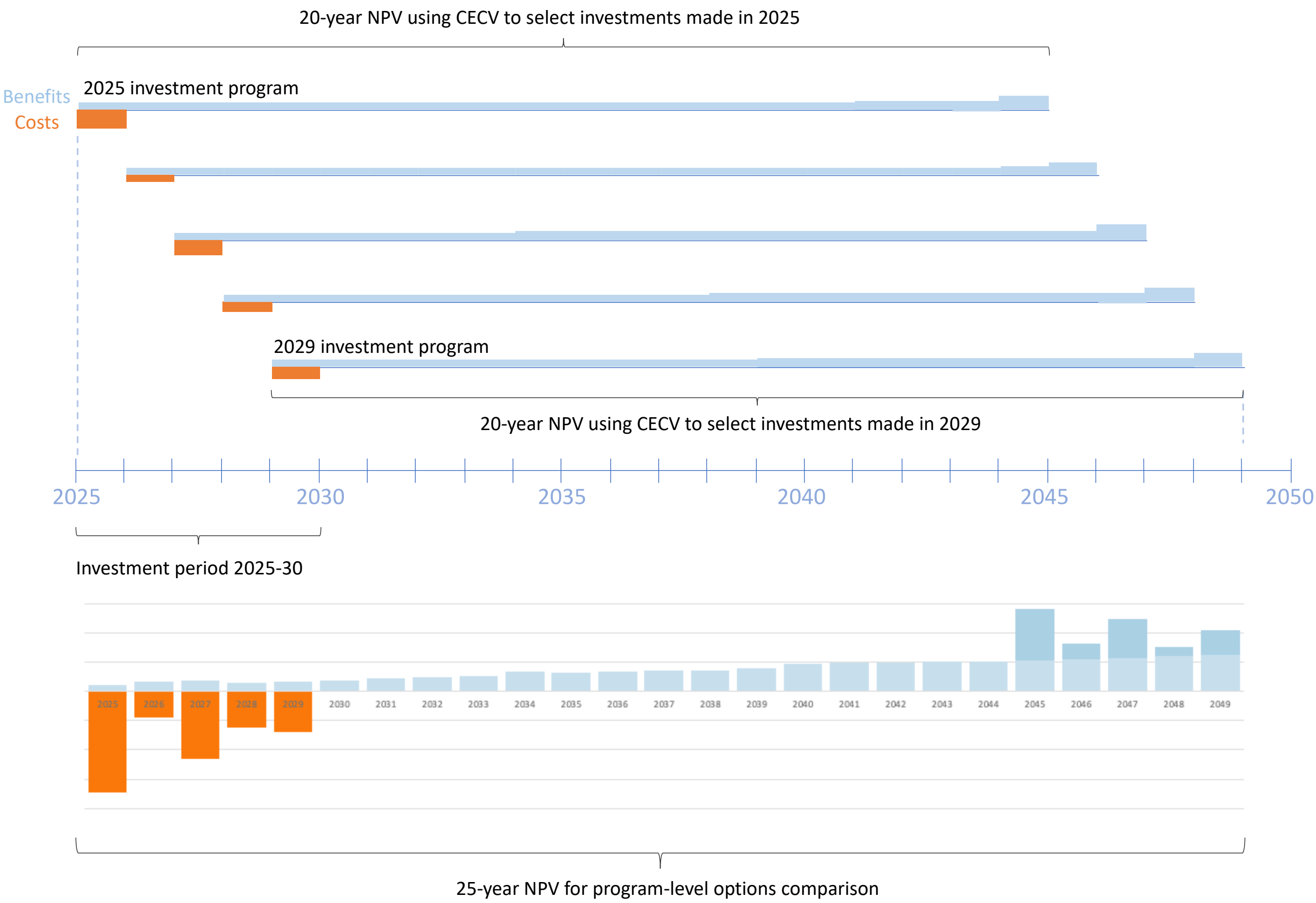
[88] Refer section 0

Approach to NPV calculation for comparing options

When choosing between different investment options to resolve an individual network constraint, we use the modified CECV to estimate the future market benefit of each one. In keeping with the AER's CECV methodology we calculate the NPV of the future alleviated export curtailment associated with each possible investment over a 20-year forward horizon from the point of investment. Hence our NPV analysis for comparing different investment options to resolve a constraint arising in 2025[89] considers the 2025-2044 period, and when we assess options to resolve a constraint arising in 2026 we consider the CECV value over the 2026-2045 period, and so on.

When we consider an overall 5-year investment plan and compare it against an alternative 5-year plan, as we do to compare the options in this business case, we use a 25-year horizon for the cost/benefit comparison, comparing NPV over the 2025-2049 period. In this case, were we to use a 20-year NPV from 2025 we would be truncating the future benefit cashflows for those investments that are made in 2026, 2027, 2028 and 2029. This methodology is illustrated in Figure 13 below.

Figure 13: 25-year NPV use to compare different 5-year work programs



Where the NPV horizon exceeds the timeframe of the CECV data we use the method in the AER's CECV methodology to project CECV values forward based on the final three years of CECV data. For investments in assets that have a service life greater than the 20-year NPV period we include an asset terminal value in the cashflow in the final year of the NPV window.

[89] In this section when we refer to a year like 2025 we mean the regulatory year commencing in that year

Appendix D – Our Distributed Energy Transition Roadmap 2020-2025