CER integration strategy

2025-30 Regulatory Proposal

Supporting document 5.7.15

January 2024

SA Power Networks

Empowering South Australia

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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
CEC	Clean Energy Council
CECV	Customer Export Curtailment Value
CER	Customer energy resources
CSIP-AUS	Common Smart Inverter Profile - Australia
CWG	Connections Working Group
DER	Distributed Energy Resources
DERIWG	Distributed Energy Resources Integration Working Group
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
ESB	Energy Security Board
EV	Electric Vehicle
EVM	Enhanced Voltage Management
FCAS	Frequency Control Ancillary Services
HV	High voltage
ICT	Information and Communication Technology
ISP	Integrated System Plan
LDC	Line Drop Compensation
LV	Low voltage
LVPE	LV Planning Engine
MSO	Model Standing Offer
NEM	National Electricity Market
NPV	Net present value
Opex	Operating expenditure
PQ	Power Quality
PV	Photovoltaic
RCP	Regulatory Control Period
TOU	Time Of Use
VCR	Value of Customer Reliability
VPP	Virtual Power Plant

1 About this document

1.1 Purpose

This document sets out our strategy for the continued integration of Customer Energy Resources (**CER**)[1] with the distribution network and gives an overview of work programs we propose to undertake to deliver on this strategy in the 2025-30 regulatory control period (**RCP**). It includes a summary of the associated business cases and outlines how our strategy and our proposed work programs align with relevant guidance provided by the Australian Energy Regulator (**AER**).

This document is intended to satisfy the requirements of the Distributed Energy Resources *(**DER**) Integration Strategy* that distribution network service providers (**DNSPs**) are expected to include as part of their regulatory proposals in accordance with the AER's *DER integration expenditure guidance note*[2].

1.2 Related documents

Table 1: Related documents

Ref	Title	Author	Version / date
5.7.3	Business case: CER Compliance		
5.7.4	Business case: CER Integration		
5.7.5	Business case: Demand Flexibility		
5.7.6	Business case: Network Visibility		
5.7.7	Business case: Innovation Fund		
5.7.9	CER integration modelling methodology		
Attachment 18	Tariff Structure Statement		

[1] The AER generally refers to customers' energy resources as Distributed Energy Resources, or DER. For the purpose of this document we refer to these as CER, and we take CER and DER to be synonymous.

[2] AER, *'DER integration expenditure guidance note'*, June 2022, accessible via [https://www.aer.gov.au/documents/aer-final-der-integration-expenditure-guidance-note-june-2022], last accessed 25 January 2024.

2 Summary: supporting the energy transition in 2025-30

No other large-scale electricity network in the world is operating with the level of distributed energy that exists in South Australia. As South Australia's world-leading transition to renewable energy continues, we are pursuing a comprehensive, integrated long-term strategy for CER integration that aims to manage the changing role of the distribution network through an efficient combination of price signals (tariffs), non-network solutions to shift and shape loads and targeted investments in network capacity to maintain export service performance.

The programs we are proposing for the 2025-30 period represent the next phase in a journey that began with our 2017 Future Network Strategy[3] and build on the successful execution of the plans set out in our 2020-25 Regulatory Proposal[4] and our Distributed Energy Transition Roadmap[5].

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. We have introduced cost-reflective 'solar sponge' tariffs, begun the process of shifting hot water loads to the daytime, improved voltage management across the network, developed new 'emergency backstop' solar generation shedding systems and, most importantly, successfully implemented the transition from static export limits to 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 by extending dynamic operating envelopes (DOEs) to flexible loads, increasing visibility of our LV network, continuing the transition to more cost-reflective tariffs (including the introduction of export tariffs) and progressively and prudently adding export capacity to maintain export service levels in line with growth in demand.

The table below provides a summary of the costs (2025-30, $2022, $ millions) and benefits (Net present value (**NPV**), $2022, $ millions) of our four proposed 2025-30 CER integration programs. Further details are included in the body of this document.

Table 2: Summary of CER integration expenditure and benefits

Program	Capex	Opex step change	NPV	Quantified benefits
CER integration (supporting systems)	14.39	3.85	16.44	CECV
CER integration (new export capacity)	46.42	-	18.94	CECV
Demand flexibility	6.68	-	6.67	CECV, VCR
CER compliance	4.96	2.24	4.71	CECV, FCAS
Network visibility	7.93	5.96	58.26	CECV, Safety, Voltage reduction
Totals	**80.38**	**12.05**		

[3] SA Power Networks, '*Future Network Strategy 2017-2030*', supporting document 5.17 to our 2020-25 regulatory proposal, accessed at [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*.

[4] SA Power Networks, *2020-25 Regulatory Proposal, An overview for South Australian electricity customers*, accessed at [www.aer.gov.au/system/files/SAPN%20-%20%20Electricity%20Distribution%20Proposal%202020-2025%20-Overview%20-%20January%202019_0.pdf], last accessed 25 January 2024.

[5] SA Power Networks, *Distributed Energy Transition Roadmap 2020-2025*, accessed via *[*www.sapowernetworks.com.au/future-energy/*],* last accessed 25 January 2024.

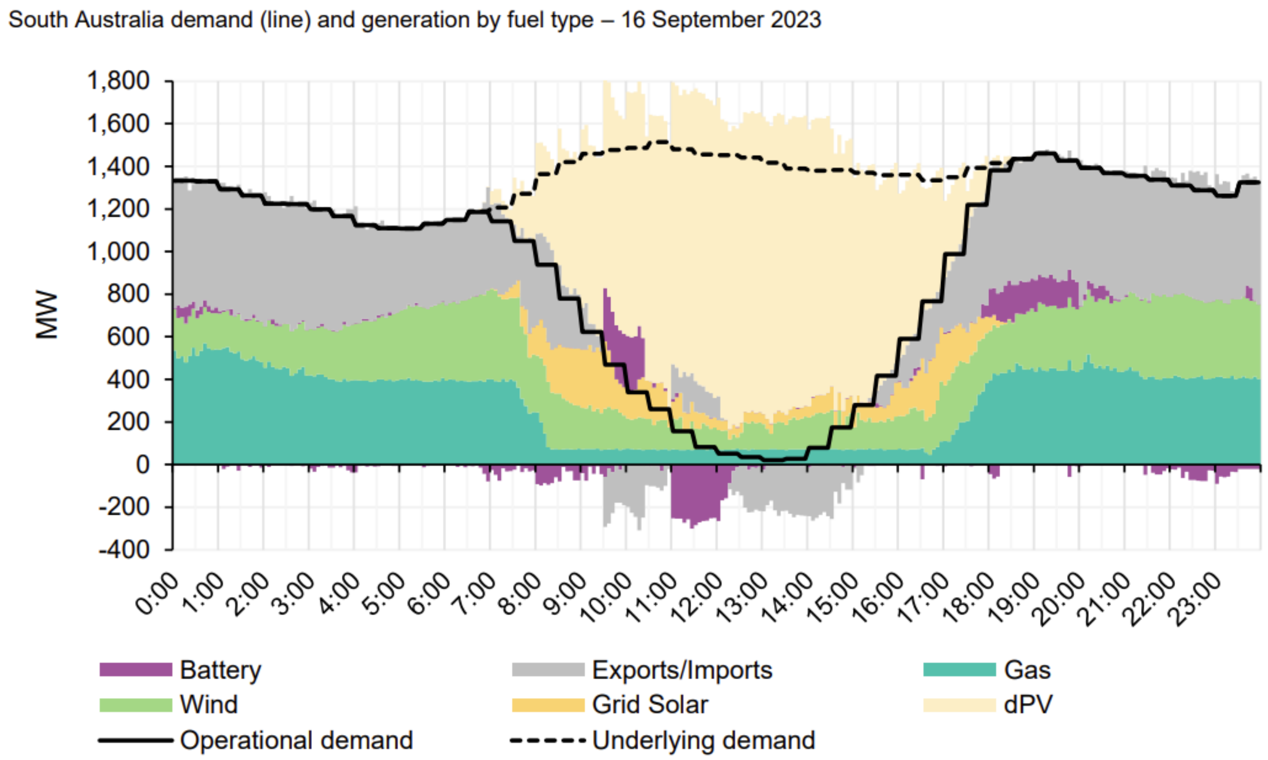
3 Background: the energy transition in South Australia

South Australia has the highest ratio of rooftop photovoltaic (**PV**) generation to operational consumption of any region in the National Electricity Market (**NEM**). As at October 2023 almost 350,000 homes and businesses have installed rooftop solar, more than one in three premises. Uptake continues to grow strongly as homes and businesses seek access to low-cost renewables, while falling PV system costs also mean that the average system size is also increasing each year. Installed rooftop PV capacity currently stands at more than 2.5 GW, making rooftop solar the largest source of generation in the state.

The high penetration of rooftop PV means that we now regularly experience reverse power flows across large areas of the distribution network during mild, 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[6]. Operational demand in South Australia may fall below zero before the end of 2023.

Figure 1: SA Operational Demand and Generation mix on 16 September 2023[7]



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 the Australian Energy Market Operator (**AEMO**) in balancing supply and demand and maintaining power system security, particularly during spring and early summer.

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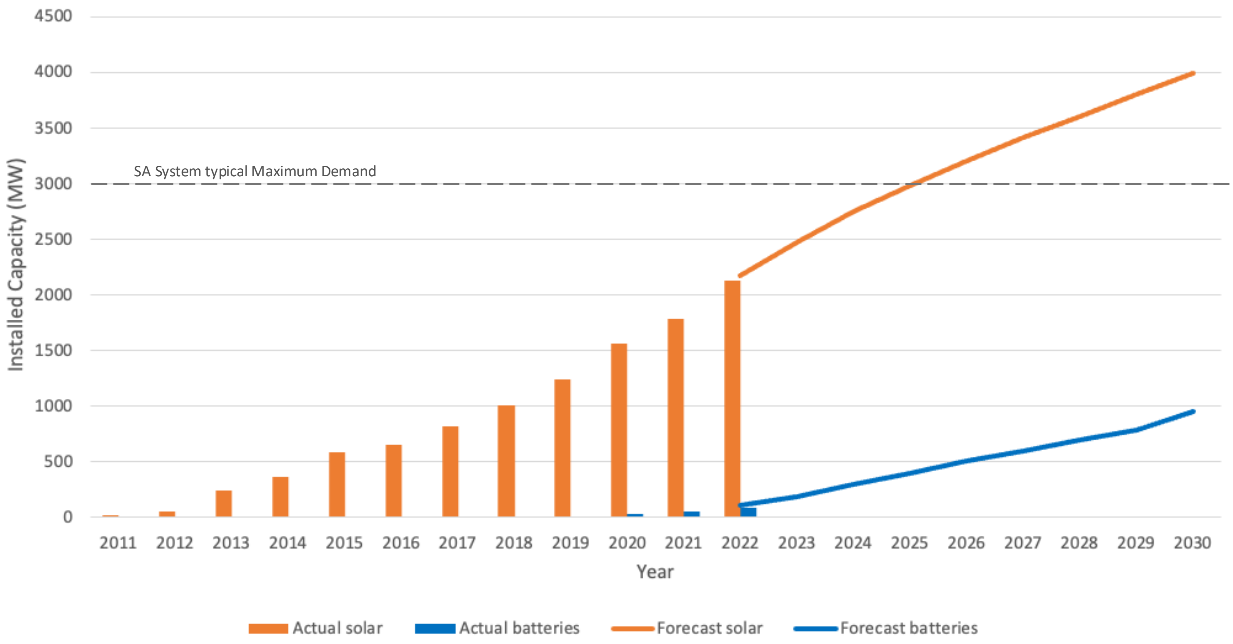
[6] AEMO, *Quarterly Energy Dynamics Q3 2023*, accessed at [https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q3-2023-report.pdf?la=en], accessed November 2023

[7] Ibid.

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.

Historical and forecast CER uptake in South Australia is shown in Figure 2 below.

Figure 2: SA CER forecasts, AEMO ESOO 2022 Step Change scenario



Although behind-the-meter batteries help to soak up some of the surplus energy from rooftop solar, new solar capacity continues to grow at a higher rate than new battery capacity and daytime reverse power flows are continuing to increase across the network year-on-year. Based on current forecasts of solar and battery uptake, export demand will exceed available export capacity in many parts of the network through the 2025-30 RCP, with constraints arising primarily at the Low Voltage (**LV**) transformer level.

4 Our approach to CER integration

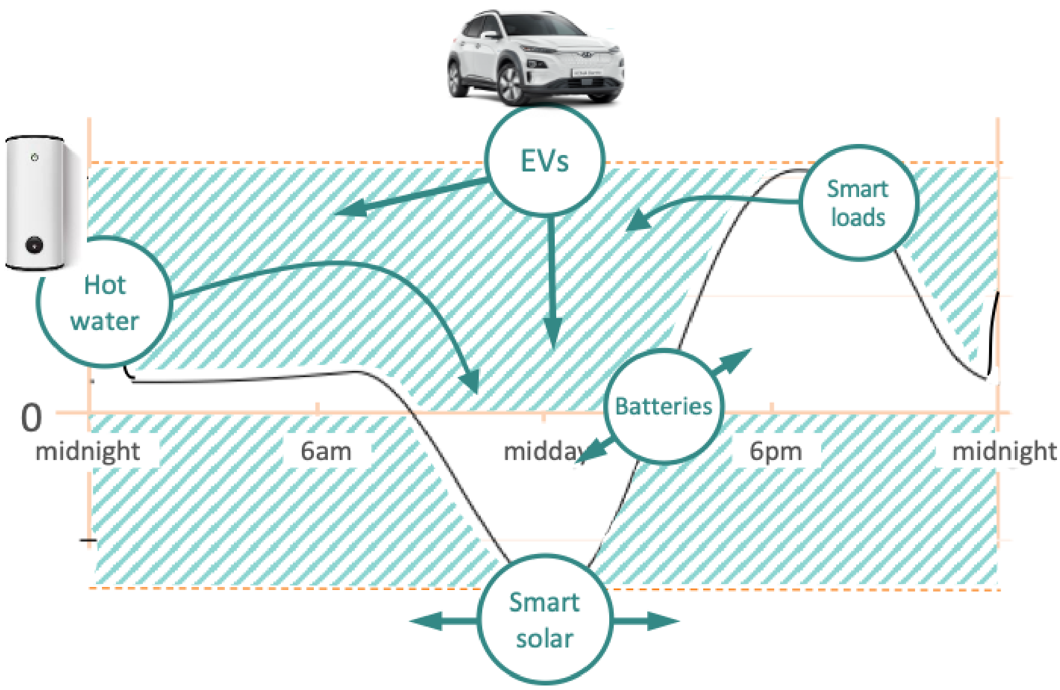
4.1 Overview

The primary goal of our 2025-30 CER integration program is to ensure that we continue to meet customer demand for the export service through the 2025-30 period.

Our CER integration strategy aims to achieve this as efficiently as possible by first pursuing a range of measures to manage demand such as: tariffs, incentives, dynamic operating envelopes and other non-network solutions. These initiatives act to increase daytime load, soak up solar, reduce peak demand, manage local network constraints and increase utilisation of existing network capacity.

Since 2020 our primary focus has been on developing the capability to enable flexible exports (DOEs) for solar customers. This capability is now in place and forms the foundation of our CER integration approach going forwards. As we move into the 2025-30 period, other key areas of interest include continuing to encourage electric hot water loads to shift from overnight to daytime (a very significant opportunity for offsetting daytime solar given there is around 800MW of hot water load in South Australia), and ensuring that future electric vehicle loads are kept out of peak times and, where possible, aligned with solar output. These and other non-network solutions are illustrated in Figure 3 below.

Figure 3 – Non-network solutions for CER integration



Only when these approaches are not sufficient to maintain export service performance do we consider targeted investments in network augmentation to add additional export capacity.

4.2 Non-network solutions

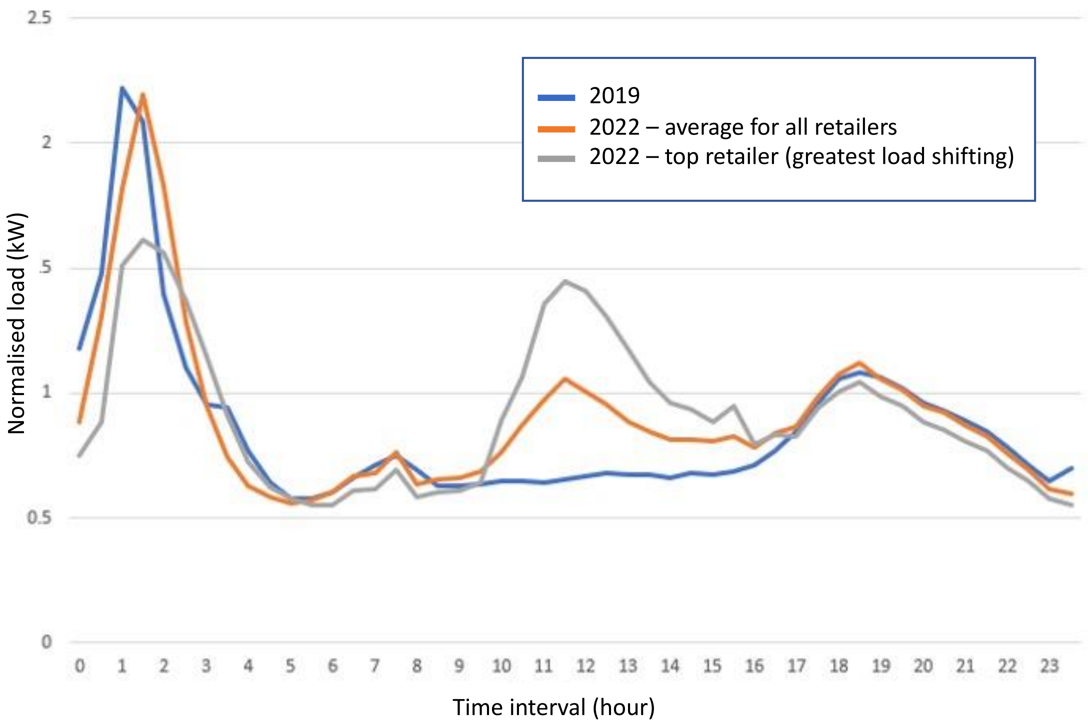
The sections below summarise the non-network solutions we are proposing as part of our CER integration strategy for 2025-30.

4.2.1 Tariffs: rewarding efficient use of the network

In 2020 we became the first Australian DNSP to introduce Time of Use (**TOU**) tariffs with an extra-low 'solar sponge' rate during the middle of the day to encourage shifting of discretionary loads to the daytime.

These tariffs were introduced first for controlled loads (primarily hot water in SA) as part of a broader strategy to transfer control over scheduling electric hot water from ourselves to the retailer. This enables and encourages retailers to shift hot water loads from overnight to the daytime to take advantage not only of our low network tariff, but also increasingly lower daytime wholesale electricity prices in SA due to high levels of solar. Since then we have observed retailers begin to shift blocks of controlled hot water loads from overnight to the daytime, and we are actively engaging with retailers to encourage this.

Figure 4: 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[8]



At the present time, AGL is conducting a trial with metering provider PlusES to test an even more dynamic scheduling scheme that can vary the timing of hot water loads on a daily basis to track wholesale price, a level of demand-side flexibility and market efficiency that would not have been possible under our traditional, pre-2020 approach to controlled load[9].

Since 2021 every residential customer with a smart meter has also been assigned to a solar sponge TOU tariff for their regular household load, creating the opportunity for all customers – but particularly those without their own solar – to save money by switching loads to the daytime. We have begun to observe an increase in average daytime loads for customers on these tariffs as a result.

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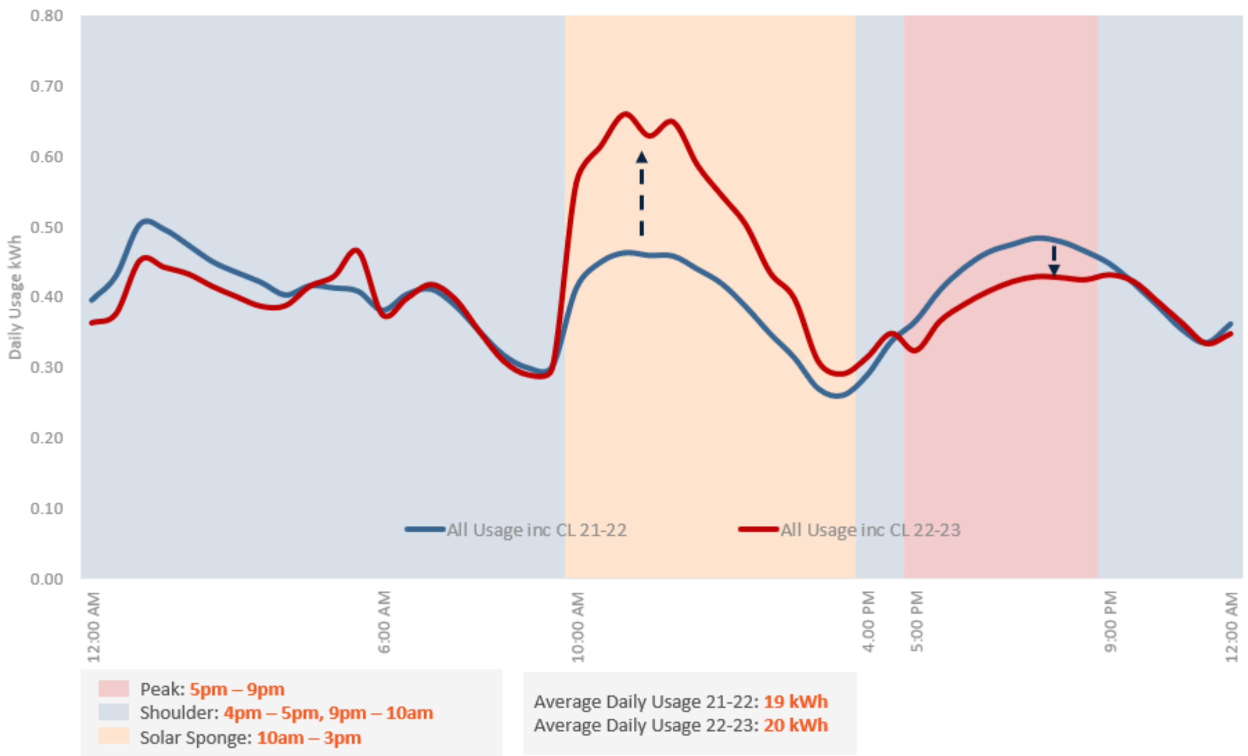
[8] The chart shows the average daily load profile for a sample of electric hot water customers (normalised to remove differences in customer size) in 2019, prior to the change in tariff arrangements, and in 2022, two years after the introduction of the 'solar sponge' tariff for controlled load in 2020. Averaged across all energy retailers in the sample set, some shifting of overnight load to the daytime can be observed (orange line). There is consider 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.

[9] See AGL media release from 24 February 2023, available via: [www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2023/february/agl-and-plus-es-launch-smarter-hot-water-controls-in-south-austr], last accessed 26 January 2024.

We propose to continue with the residential time-of-use (RTOU) solar sponge tariff as our standard tariff for residential customers in 2025-2030, with minor changes to increase the duration of the solar sponge period by one hour to end at 4pm instead of 3pm and to bring forward the start of the overnight off-peak period to midnight from 1am to align with changing usage patterns[10].

We also propose to offer an alternative TOU tariff with stronger price signals on an opt-in basis for engaged customers with more capacity to shift and schedule loads. Based on our residential 'Electrify' trial tariff (RESELE) this tariff has a lower daytime rate than our standard tariff and a shorter evening peak period (5pm – 9pm) with a higher peak rate. In our trials this tariff has proved to be effective in encouraging customers to change their behaviour and shift loads to increase daytime consumption and reduce peak demand, with 71% of solar customers and 80% of non-solar customers who opted into the tariff saving money as a result.

Figure 5: Residential load profiles for a sample of 97 customers with our 'Electrify' trial tariff showing shift in behaviour for this cohort from 2021/22 to 2022/23



In line with the Australian Energy Market Commission (**AEMC**) 2021 *Access, pricing and incentive arrangements for distributed energy resources* rule change[11] we propose to introduce export tariffs from July 2025 for residential customers.

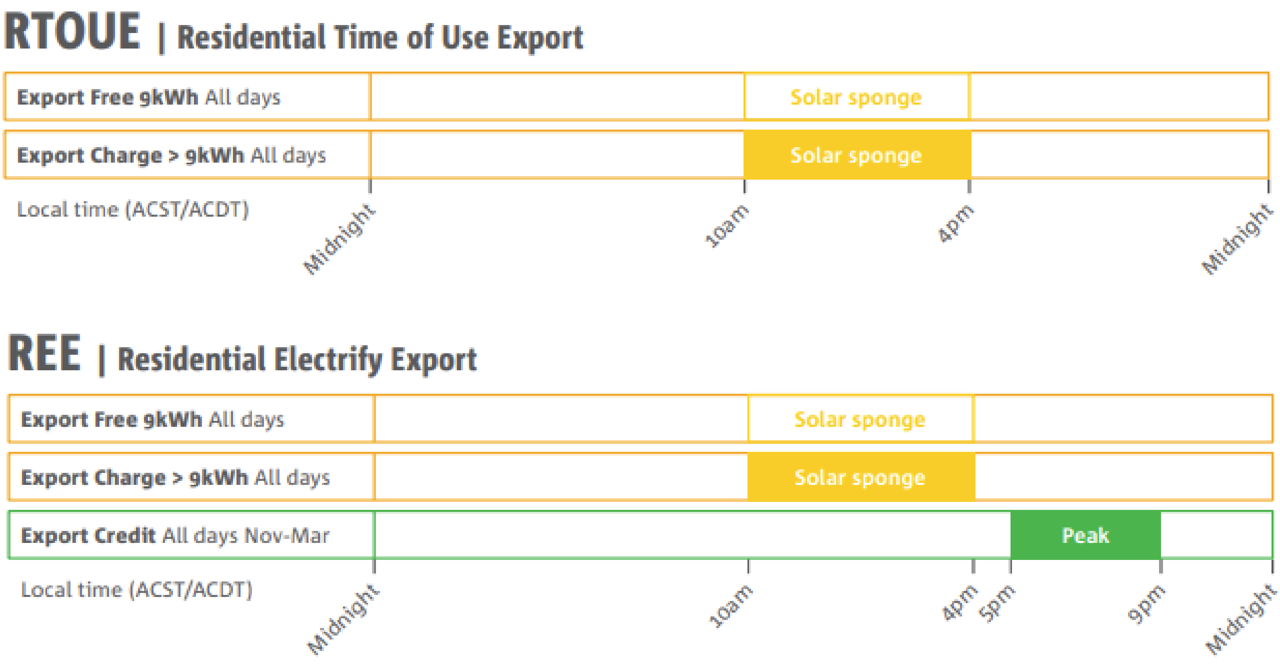
Export tariffs will apply to energy exports between 10am and 4pm above a free threshold of 9kWh/day[12]. On days where a customer exports less than the free allowance of 9kWh in the 10am-4pm period, the remainder is rolled forward to subsequent days within the same billing period. We also propose to incorporate an export credit ('negative price') for residential export customers on our Electrify (RESELE) tariff who export between 5pm and 9pm during the summer months. These price signals will further improve the cost-reflectivity of our tariffs and reward more efficient use of network capacity by export customers in the long run.

[10] Refer Attachment 18, Tariff Structure Statement, for more details.

[11] AEMC, *Access, pricing and incentive arrangements for distributed energy resources* rule change, August 2021.

[12] Reflective of the 'intrinsic capacity' of the network for exports that customers already fund through their consumption tariffs.

Figure 6: Proposed export tariff structures for 2025-30



Our tariff strategy relies on customers having the necessary metering. We have been active supporters of the AEMC's proposal to accelerate the remainder of the smart meter rollout from 2025 onwards with a target of completing the rollout to all customers by 2030, and we have partnered with retailer Alinta Energy and metering provider Intellihub to put forward a rule change request to achieve this[13]. Although the final outcome is still subject to the rule change process, it is our expectation that the accelerated rollout will occur.

We have factored the expected benefits of the continued transition to more cost-reflective tariffs – increasing daytime loads to soak up solar exports, reduced peak demands and more efficient Electric Vehicle (EV) charging behaviours – into our modelling of future power flows in the network, assuming that there will be an accelerated smart meter rollout.

4.2.2 Flexible exports: dynamic operating envelopes as standard for all CER connections

In 2018 we became the first Australian DNSP to put forward a plan to transition from static export limits for new solar customers to dynamic limits, now known as flexible exports or dynamic operating envelopes (**DOEs**). The associated business case was the centrepiece of our CER management strategy in our previous Regulatory Proposal for the 2020-25 RCP.

In September 2021 we launched Australia's first flexible exports connection offer for solar customers using the Common Smart Inverter Profile – Australia (**CSIP-AUS**) communications standard[14]. 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 a 1.5 kW static limit, reflective of the average intrinsic hosting capacity of our network.

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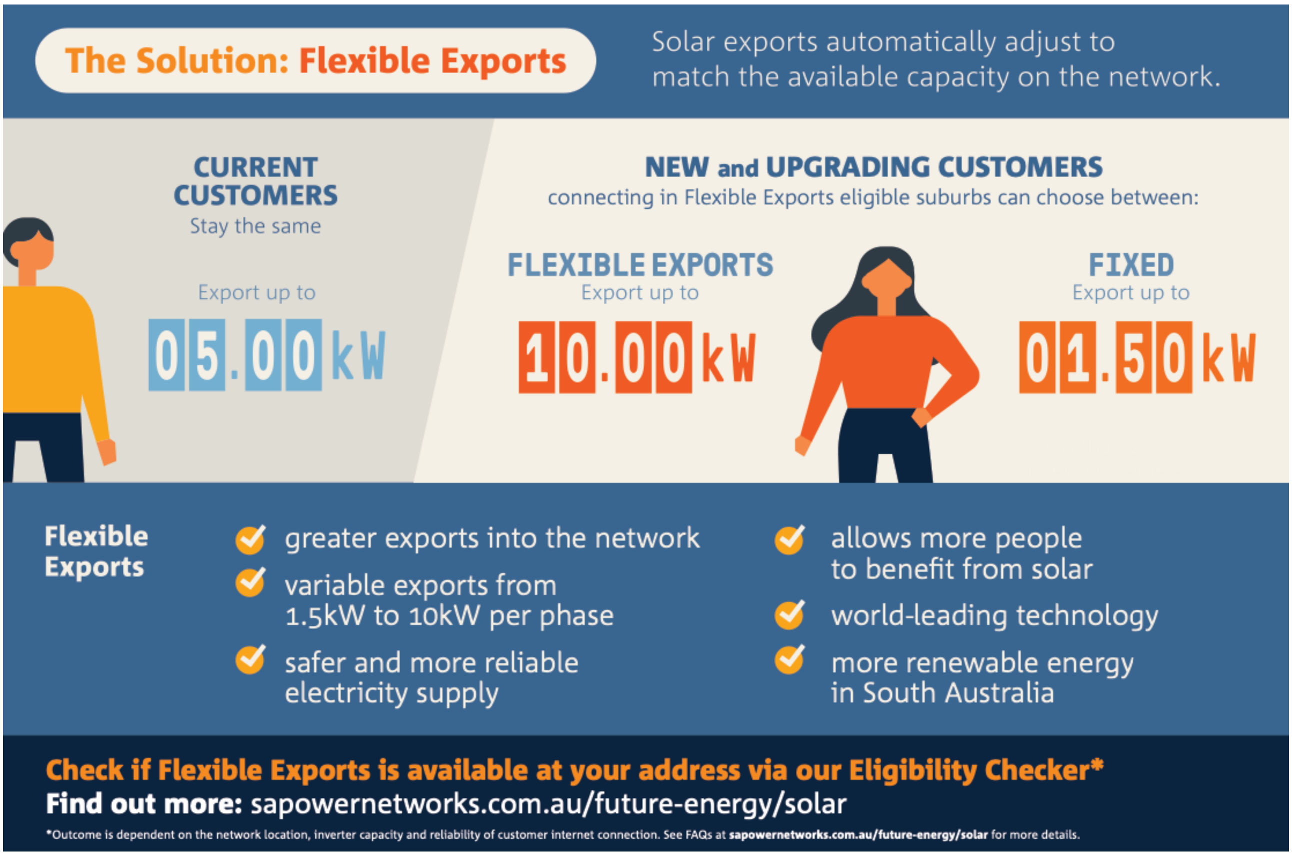
[13] Intellihub, SA Power Networks and Alinta Energy, *Rule change request: Accelerating the deployment of smart meters and unlocking their benefits*, 22 September 2023, available via: [www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment], accessed 26 January 2024.

[14] 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: [www.arena.gov.au/assets/2021/09/common-smart-inverter-profile-australia.pdf], accessed January 2024.

Figure 7: Extract from SA Power Networks' Flexible Exports infographic for customers



Since 1 July 2023, under the SA Government's Smarter Homes regulations, all new solar PV systems in South Australia are required to support the CSIP-AUS standard and be compatible with flexible exports, and we are progressively rolling out access to the scheme across our network. 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.

Flexible exports present a step change in customer access to our networks available export capacity. It significantly increases utilisation of our 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.

The successful implementation of our flexible exports capability in the 2020-25 period underpins our CER integration approach for 2025-30 and beyond. Having this capability in place now allows us to take a measured, proactive, targeted and efficient approach to investment in new export capacity to meet and manage forecast growth in demand for the export service. Where it is efficient to do so, we will make targeted investments to relieve constraints in areas where curtailment with flexible exports is high and export service levels are below customer expectations as a result.

Where network augmentation is not practical we will use flexible exports to manage demand dynamically within network limits. This enables us to provide the best service level we can from existing assets, which will be a much greater level of service than could be achieved using static limits. Our approach to capacity allocation is consistent with the principles set out in the AER's November 2023 draft *Interim export limit guidance note*[15] and is described in detail in our CER integration business case[16].

[15] AER, Interim export limit guidance note – for consultation, November 2023, available via: [www.aer.gov.au/documents/draft-export-limit-interim-guidance-note-november-2023], accessed 26 January 2024.

[16] 5.7.4 – Business case: CER integration

The costs to develop the systems and processes required for flexible exports have largely been incurred in the 2020-25 period. Our 2025-30 proposal includes ongoing expenditure to maintain these systems and scale them in line with the forecast growth in new solar connections.

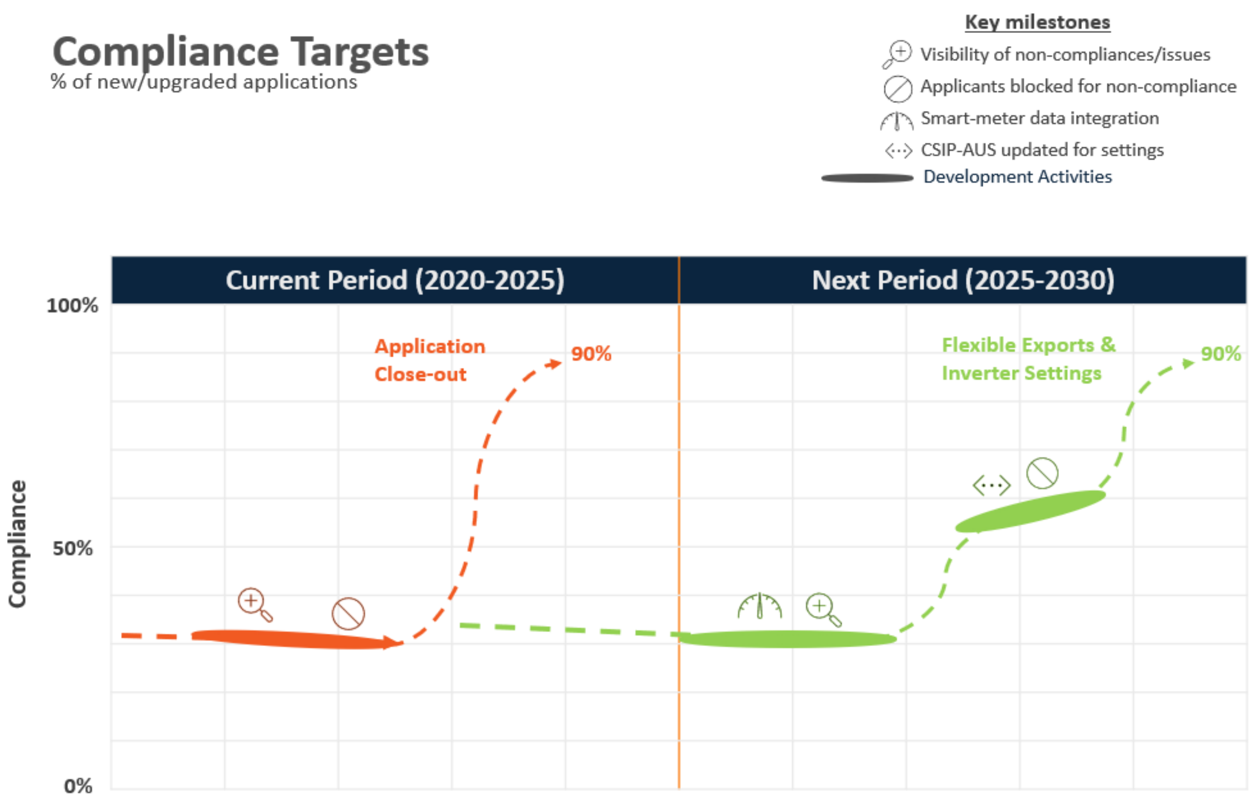
4.2.3 Improving compliance to CER technical standards

Recent studies by AEMO, SA Power Networks and others have revealed significant levels of non-compliance to CER technical standards and regulations across the population of installed CER equipment in South Australia and in the broader NEM. Poor compliance to standards such as AS4777 impacts negatively on network hosting capacity and hence export service performance. It also contributes to system security risk at times of low system load by making the system less resilient to disturbances and potentially impeding the operation of emergency backstop measures for solar curtailment.

SA Power Networks has developed a Compliance Strategy that sets out a ten-year program of work to improve levels of compliance to CER technical standards by installers and customers, and we are currently executing the first phase of this strategy. We propose to continue with our compliance program in the 2025-30 period.

To date, our compliance program has focused on improving the CER connection application process, developing a new connections portal and raising industry understanding of compliance obligations. In phase 2, our 2025-30 program, we will continue to extend our compliance capabilities and industry engagement. This includes developing the capability to use smart meter data analytics to detect potential non-compliance. The 10-year plan is illustrated in Figure 8 below.

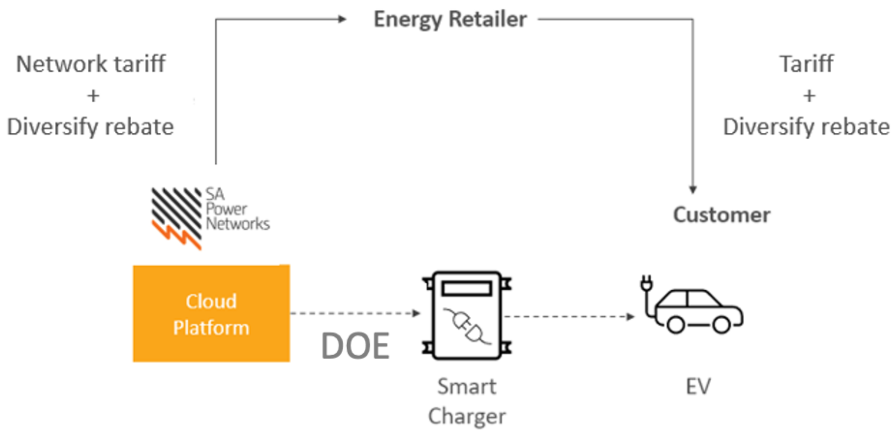
Figure 8: SA Power Networks' CER Compliance Program targets



4.2.4 Activating demand flexibility

As part of our overall strategy to increase the level of demand-side participation we intend, in the 2025-30 period, to extend the systems we have developed for flexible exports to enable DOEs on the load side, and to use this capability to offer new flexible load connection options and incentives to customers. Our 2025-30 demand flexibility program will build on learnings from trials that we are undertaking prior to 2025 such as our proposed 'Diversify' tariff trial, which will provide a financial incentive to customers who enrol their smart electric vehicle (EV) chargers to operate within a DOE.

Figure 9: Diversify tariff trial concept



Dynamic load limiting schemes based on DOEs on the load side are naturally complementary to tariffs insofar as tariffs provide a long-run price signal that promotes efficient use of the network over time whereas DOEs provide the capability to manage short-run and localised constraints. DOEs also allow for a 'firmness' of demand response that can be used as the basis of lower-cost flexible connection options for large commercial and industrial loads, as well as providing a means to shape loads to smooth the load spikes that can occur at TOU tariff price boundaries.

In the residential setting, hot water and EV charging loads present the most significant opportunities for load flexibility in the near term. In the commercial space, the rollout of public EV charging infrastructure presents an important new opportunity to reduce network cost through demand flexibility, particularly in regional areas of the network that are capacity-constrained. Other potential beneficiaries of future flexible connection arrangements include community batteries and flexible commercial and industrial loads like datacentres or irrigation.

4.2.5 Improving network visibility

An important part of our long-term CER integration strategy is to improve our visibility of reverse power flows and voltage variation across our network, particularly the LV network. Since 2020 we have put in place the foundational systems to enable this, including deploying the Future Grid Compass platform for storage and analysis of time series data from smart meters and CER devices. We have also completed our planned rollout of transformer monitors to a sample of around 2,000 LV transformers, primarily to improve load forecasting, and have been exploring the potential use of smart meter data in several applications using data from a sample set of around 25,000 smart meters, procured from two metering providers.

We propose to continue to develop our network visibility and modelling program in 2025-30, scaling up to make use of the new 'basic power quality data' dataset that we expect to begin to receive from all smart meters from mid-2025 onwards under the rule change arising from the AEMC's metering review.

While network visibility is a key enabler for effective CER integration, it is important to note that our network visibility program is a broader program that underpins improvements to a range of network operational, planning and safety functions. These are detailed in the associated business case[17]. From the perspective of CER integration and the delivery of the export service, the relevant elements of this program are:

- upgrades to SCADA metering at a number of substations where reverse power flows are forecast in the 2025-30 period but where there is currently either no metering, or the existing metering cannot discriminate between forward and reverse flows. This is necessary to ensure that our Advanced Distribution Management System (ADMS) state estimation works correctly, for flexible exports constraint estimation and for capacity planning;

- use of smart meter data to improve the accuracy of our LV network hosting capacity model, which allows for higher flexible export limits for customers;

- use of smart meter data analytics to detect non-compliance to AS4777 settings as part of our 2025-30 compliance program, as described above; and

- use of smart meter data to improve tuning of network voltage management equipment to support our efforts to progressively reduce average voltages across the network.

4.3 Network solutions for additional export capacity

Where we are unable to continue to meet and manage demand for the export service using non-network solutions alone, we propose to make targeted network investments to increase the network's export hosting capacity. These investments are mostly in the LV network, which is where export constraints from rooftop solar and other CER arise first.

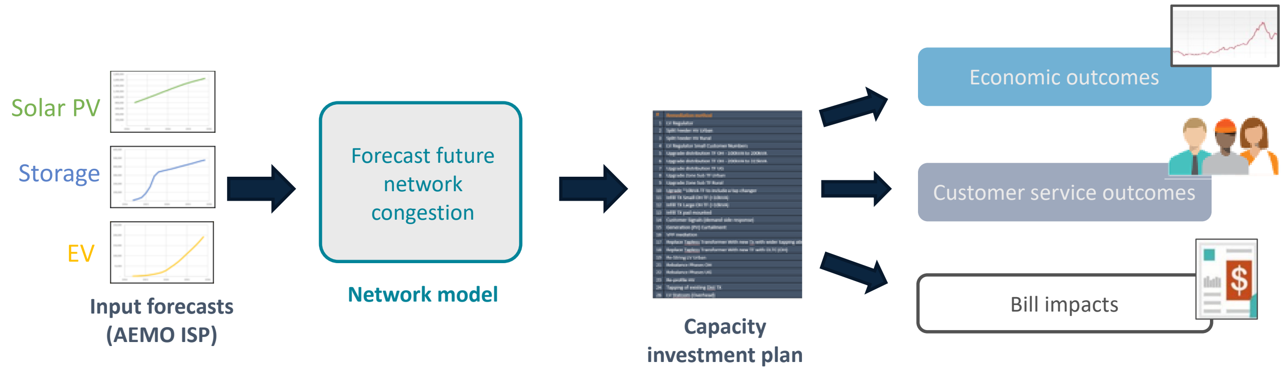
To determine the investments required we have developed a detailed network model, shown in Figure 10 below. This builds on the hosting capacity analysis and network modelling work we undertook in 2017 and 2018 during the development of our 2020-25 Regulatory Proposal, as well as significant work undertaken since then to develop, extend and refine this modelling to support the calculation of DOEs for flexible export customers.

The model 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, electric vehicles, etc. derived from AEMO's Integrated System Plan (**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 and we have modelled a range of different investment scenarios, options and sensitivities during the development of our proposed plan. These are described in detail in the associated business case[18].

[17] 5.7.6 – Business case: network visibility

[18] 5.7.4 – Business case: CER integration

Figure 10: Methodology used to forecast future export capacity investment using our LV Planning Engine



The investment plan that we propose for the 2025-30 period is intended to maintain export service performance at no less than 95% for 95% of customers through to 2030. A 95% service level means that export customers can expect to have their exports curtailed for no more than 5% of daylight hours through the year[19], which represents a modest reduction in export service performance compared to today's average of around 98% for flexible exports customers.

During our stakeholder engagement program and our customer values research we presented customers and other stakeholders with a range of different export service levels and an indication of the associated bill impacts to maintain them through the 2025-30 period (noting that maintaining a higher level of service performance requires more investment than a lower one). Our target to maintain a 95% level of service for 95% of customers reflects the level of service performance our customers and other stakeholders indicated they want to receive and are willing to pay for[20].

As well as maintaining the level of export service performance customers want, our proposed network investment program will deliver positive market benefits to all customers as assessed using a variant of the AER's Customer Export Curtailment Value (CECV)[21].

Before assessing the need for network investment in export capacity, our modelling first takes into account the forecast impacts of EVs, batteries and the suite of non-network solutions described above in order to establish the base case, i.e. the service level outcome if we were to only rely on non-network solutions and not make any investments in additional network capacity. This includes:

- 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;
- the availability of flexible exports as standard for all new solar customers by 2025, which significantly reduces the duration of export curtailment, and hence increases the export service level, for customers in constrained areas;
- 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;

[19] This is our preferred measure of export service performance and is based on a study of different export service metrics undertaken by the RACE for 2030 CRC. See Langham, E.L., Guerrero, J., Nagrath, K. and Roche, D., *Measuring and communicating network export service quality*, 2022, available at https://issuu.com/racefor2030/docs/21.n2.f.0186_export_service_quality_metrics_final

[20] For more details see 5.7.4 – Business case: CER integration

[21] Our modelling takes into consideration both the CECV and an additional benefit factor to reflect the forecast benefit of avoided generation capacity investment, as detailed in 5.7.4 – Business case: CER integration

- 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.

We have also modelled the interaction with our broader asset replacement expenditure (repex) and capacity augmentation expenditure (augex) programs to ensure there is no double counting of expenditure, as described further in section 6 below.

The following sections summarise the network investments we propose to undertake 2025-30, being those required to maintain export service performance after all of the above have been taken into account.

4.3.1 Enhanced voltage management: LDC and transformer tapping program

We propose to invest in further improvements to network voltage management to reduce daytime voltage rise in high solar areas. This includes the installation of dynamic voltage control (Line Drop Compensation, or LDC) equipment at a further 54 zone substations, continuing from the rollout undertaken for our 2020-25 Enhanced Voltage Management (**EVM**) program. It also includes a transformer tapping program to visit and adjust over 1,600 LV transformers in constrained areas to a lower tap setting.

4.3.2 LV network export capacity augmentation

We propose to undertake capacity upgrades to 369 existing LV transformers (including replacement of old fixed-tap transformers) as well as the installation of 561 additional infill transformers to increase export capacity in areas of congestion.

4.4 Other supporting systems and related expenditure

Our 2025-30 CER integration program also includes necessary expenditure to maintain certain supporting systems that have been established since 2020. This expenditure is required under all future scenarios and options and is summarised below.

4.4.1 CER register and other systems

We are obliged under the National Electricity Rules (NER) to collect data on CER installations in South Australia and provide it to AEMO for AEMO's CER Register via an electronic interface. To meet this obligation, and to support our CER connection process and daily network planning and operations, we need to continue to maintain our internal database of installed CER and the systems that connect to it such as our CER application portal.

4.4.2 Smarter Homes and Emergency backstops

We need to continue to maintain our Smarter Homes API and the associated systems that support the activation of emergency solar generation shedding. These systems are required to enable us to fulfil our obligations to AEMO and under the SA Government's 2020 Smarter Homes regulations. This includes systems to support our role as a Relevant Agent under the Smarter Homes scheme and our role in activating responses from third-party Relevant Agents[22], as well as the systems to manage the use of emergency voltage raise to temporarily disconnect small scale solar as a last resort.

[22] 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 [www.energymining.sa.gov.au/industry/moCERn-energy/solar-batteries-and-smarter-homes/regulatory-changes-for-smarter-homes] for further details of the Smarter Homes program, accessed 26 January 2024.

These systems provide a critically important 'emergency backstop' capability to help AEMO to manage minimum system load contingency events in South Australia. This capability was activated for the first time on 14 March 2021 when minimum system load fell to dangerously low levels during a partial outage of the Heywood Interconnector. This was the first time ever that AEMO had given a direction to maintain a minimum level of operational demand, and SA Power Networks' successful activation of emergency measures to shed 71MW of distributed solar in response was possibly a world-first.

The system was used again at AEMO's direction on several days between 13 and 19 November 2022 when South Australia was islanded from the rest of the NEM due to storm damage to the transmission network, reaching a maximum level of 410 MW of curtailment on 17 November[23]. As rooftop solar capacity continues to grow in South Australia this capability will remain a critical 'last line of defence' to protect the stability of the state's electricity system during similar minimum system load contingencies in future.

4.4.3 Regional sub-transmission network voltage regulators

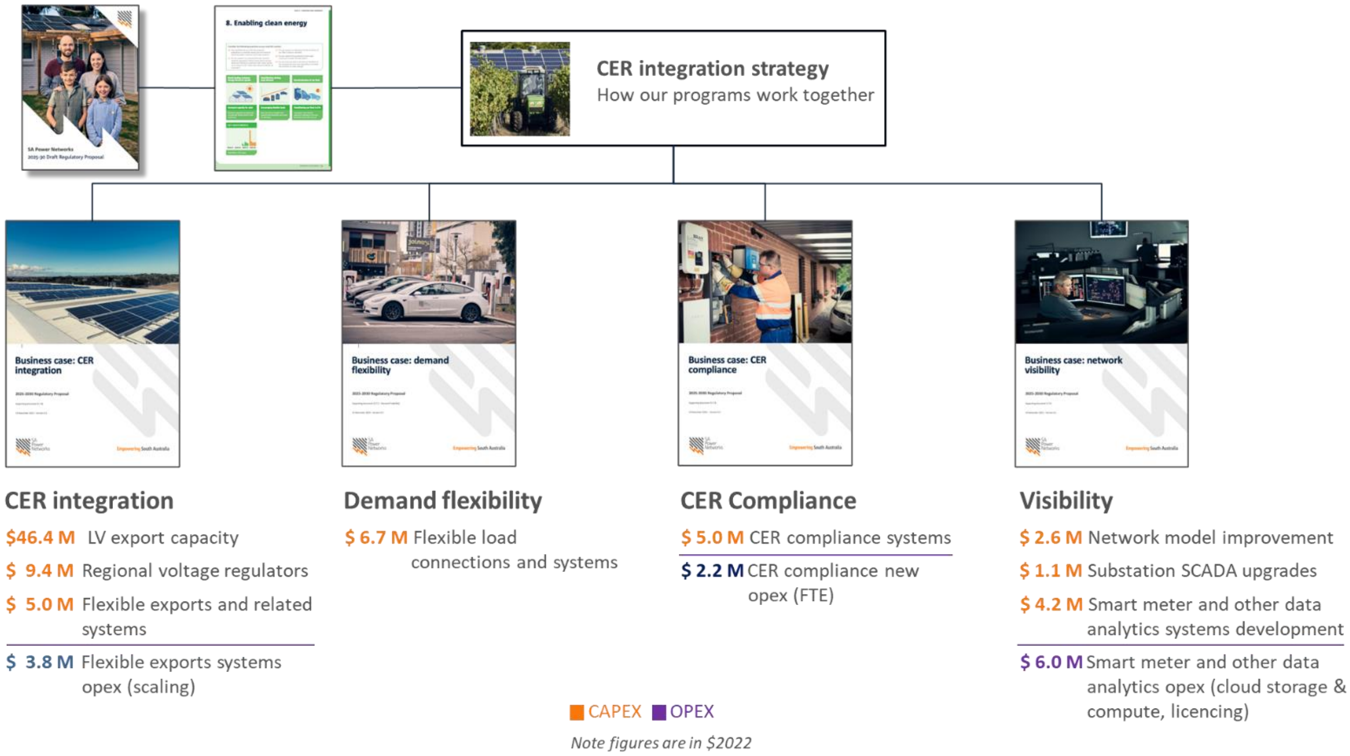
Our 2025-30 work program also includes the deployment of new voltage regulators at 11 locations in the regional sub-transmission network. This work is required to maintain voltage compliance in these parts of the network under all future scenarios and options modelled.

[23] AEMO, Preliminary Report – Trip of South East – Tailem Bend 275 kV lines on 12 November 2022, accessed at https://wa.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en

5 Costs and benefits: our CER integration business cases

The four primary work programs we propose to undertake in 2025-30 to deliver on our CER integration strategy have been developed over the last 18 months through a process of modelling, forecasting, stakeholder engagement and options analysis, including detailed modelling of network hosting capacity and detailed analysis of the costs and benefits of different options. These are set out in detail in the four associated business cases shown in Figure 11 below. [24,25,26,27]

Figure 11: CER integration business cases and their relationship to our regulatory proposal and this strategy



The table below provides a summary of the costs (2025-30, $2022, $ millions) and benefits (NPV, $2022, $ millions) of these programs. Further details are in the associated business cases.

24 5.7.3 – Business case: CER compliance

25 5.7.4 – Business case: CER integration

26 5.7.5 – Business case: Demand flexibility

27 5.7.6 – Business case: Network visibility

Table 3: Summary of CER integration expenditure and benefits[28]

Program	Capex	Opex step change	NPV	Quantified benefits
CER integration (supporting systems)	14.39	3.85	16.44	CECV[29]
CER integration (new export capacity)	46.42	-	18.94	CECV
Demand flexibility	6.68	-	6.67	CECV, VCR[30]
CER compliance	4.96	2.24	4.71	CECV, FCAS[31]
Network visibility	7.93	5.96	58.26	CECV, Safety, Voltage reduction
Totals	**80.38**	**12.05**		

Collectively, these programs amount to around 4% of our total capital program for 2025-30.

[28] Capex and Opex are total expenditure in $2022 for the 2025-30 period. NPV shows the NPV of costs and benefit cashflows over a longer evaluation period, which varies by business case – refer individual business cases for details.

[29] Customer Export Curtailment Value, with addition of value of avoided generation capacity investment. Refer document: 5.7.4 CER integration business case for details.

[30] Value of Customer Reliability.

[31] Frequency Control Ancillary Services costs.

6 Interrelationships, synergies and avoiding overlaps

We take a holistic approach to long-term network planning in which we consider potential synergies between different work programs. In developing our CER integration programs for 2025-30 we have taken into consideration the interactions (a) between the CER integration programs and (b) with other aspects of our overall regulatory proposal. This is important to ensure that the overall proposal delivers the right service outcomes to customers in a cost-efficient way and to avoid any overlaps or double-counting of expenditure or forecast benefits. These interactions, synergies and relationships are summarised briefly below.

6.1 Interrelationships between our CER integration programs

Our CER integration programs are intended to work together as a package to meet and manage demand for the export service in 2025-30.

The network model that underpins the capacity augmentation plan in our CER integration program first takes into consideration the positive impact of our tariffs and all the various non-network solutions in our other work programs. Only those areas where export capacity is forecast to be exceeded even after these effects are accounted for are considered as candidates for a network solution such as a distribution transformer upgrade.

All potential network investments have the value of the associated alleviated curtailed energy assessed against the CECV[32] to select the investments that return the best economic outcome. In this analysis, only the value of the incremental alleviated curtailment is considered, that is, the additional alleviated curtailment attributable to the network augmentation assuming that all non-network solutions have already been applied.

The CECV benefits attributable to the alleviated curtailment from non-network solutions are captured separately in their respective business cases, and are calculated by comparing the forecast curtailment profile in the network expenditure base case (that is, before any expenditure on network augmentation) with and without the non-network solution in place.

6.2 Relationships with Business-as-usual (BAU) Quality of Supply (QoS) work

Our 2025-30 BAU QoS program is a continuation of our normal augmentation expenditure required to manage demand and maintain compliance in the LV network and to address customer QoS issues arising, such as over- or under- voltage or flicker. It comprises a capital program of enhancement, infill and upgrade works to LV transformers and related assets, as well as annual operating costs to undertake regular load surveys in the LV network for capacity planning purposes (i.e. load growth) and to investigate customer-reported QoS issues.

Historically, around 1/3 of this expenditure has been associated with general maintenance, safety and capacity work, around 1/3 has been associated with addressing under-voltage and other QoS issues, and 1/3 has been associated with addressing customer-reported over-voltage issues. Between 2016 and 2020 the number of customer-reported over-voltage issues grew significantly year-on-year as rooftop solar penetration began to reach and exceed the technical limits of the local network in many areas, leading to many more over-voltage conditions in the middle of the day, particularly in spring and autumn. This led to a corresponding escalation in expenditure in this part of the BAU QoS program.

Between 2020 and 2022 we rolled out our enhanced voltage management (EVM) program, deploying dynamic voltage management (**LDC**) at around 140 major zone substations. This had a significant positive

[32] Our CECV comprises the AER's 2022 CECV and the value of avoided generation capacity investment which has been derived by economic consultants Houston Kemp and described in their Avoided Generation Investment report which forms attachment 5.7.13 of our regulatory proposal.

impact on daytime voltage rise issues in high solar areas, and the number of customer-reported over-voltage issues dropped materially as a result.

With the transition to flexible exports as the default connection offer for all new solar customers from 2024 onwards and with the export capacity investments and non-network solutions proposed in our 2025-30 CER integration program our aim is to manage the forecast continued growth in solar without any new growth in customer over-voltage issues, maintaining customer-reported over-voltage issues, and the associated BAU QoS expenditure, at pre-solar levels through the 2025-30 period and beyond.

We have also considered the potential overlap between LV transformer upgrades that are proposed in our CER integration program to address export capacity constraints and LV areas that may also experience load constraints due to forecast peak demand growth that would be addressed through our BAU QoS program. We have used or LV network modelling tools to estimate the extent of this overlap and adjusted our BAU QoS expenditure forecast downwards accordingly to remove expenditure for transformers expected to be upgraded as part of the CER integration program.

6.3 Relationships with our High Voltage (HV) network capacity augex program

As well as helping to reduce export constraints by better matching loads to daytime solar peaks, our demand flexibility program will reduce the customer impact of extreme peak demand events. It does this by allowing for the voluntary curtailment of flexible loads (i.e. for customers that have opted into a flexible load connection with a DOE) as a first step, potentially avoiding the need for involuntary load shedding or the risk of unscheduled outages due to asset overloads.

To assess this benefit we have considered the likelihood of involuntary load shedding and the associated Value of Customer Reliability (VCR) risk from 2025 onwards, after taking into consideration the effects of the capacity investments we plan to make in our proposed capacity augex program.

6.4 Relationships with our repex program

Our CER integration program 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 (i.e. replacement due to age or condition). The hosting capacity benefits of these repex replacements are already included in the base case for our CER integration expenditure modelling: where an aging LV transformer is scheduled for replacement in an area that is also forecast to have an export constraint, we assume that the constraint will be addressed as part of the repex replacement, e.g. by replacing the transformer with a larger one. This avoids any double counting between the two programs.

6.5 Relationships with our 2020-25 transformer monitoring program

Since 2020 we have rolled out transformer monitors to a sample set of around 2,000 LV transformers. This completes the transformer monitoring program that was put forward in our 2020-25 regulatory proposal and we do not plan to roll out further LV transformer monitors in 2025-30.

These permanent monitors are used primarily for load forecasting and replace the previous use of temporary loggers for that purpose. The data from these transformer monitors is complementary to, but does not overlap with, the smart meter power quality data that is the focus of our 2025-30 network visibility program, which is intended to enable a broad range of additional use cases.

6.6 Our proposed innovation fund

Our 2025-30 regulatory proposal includes the provision for an Innovation Fund, modelled on similar funds used by other DNSPs.

The aim of the Innovation Fund is to provide a means to fund projects and programs in the 2025-30 period that are innovative in nature, in areas where we have identified that some investment is likely to be required but where the scope, costs and benefits are not yet sufficiently well-defined to develop a detailed business case.

The following projects that were initially considered for inclusion in our 2025-30 CER integration program fall into this category due to uncertainty of future scope. These have been removed from our CER integration business cases and are now considered as candidate projects for the Innovation Fund:

- changes to operational systems and interfaces to support proposed market reforms arising from the Energy Security Board (**ESB**) Post-2025 Market Review and AEMO's NEM Reform Implementation Roadmap[33]. This includes reforms that are the subject of current rule change proposals such as Flexible Trading Arrangements and the integration of price-responsive resources to the NEM ('Scheduled Lite'), as well as other potential reforms like AEMO's proposed new data services and central data platform;

- trial of an on-line platform to facilitate procurement of network services from third parties such as VPPs or aggregators, similar to the Piclo Flex platform used by several UK distribution networks to procure demand response services[34];

- an enhanced self-service connection portal enabling CER customers to access detailed network capacity information, identify the best points of connection to existing network assets, and receive indicative connection costs; and

- additional CER advisory functions and on-line resources to assist customers with optimising their use of the network.

[33] See www.aemo.com.au/initiatives/major-programs/nem-reform-implementation-roadmap, accessed 26 January 2024.

[34] See www.picloflex.com, accessed 26 January 2024.

7 Summary

We are pursuing a comprehensive, integrated long-term strategy for CER integration that aims to manage the changing role of the distribution network through an efficient combination of price signals (tariffs), non-network solutions to shift and shape loads, and targeted investments in network capacity to maintain export service performance.

The programs we are proposing for the 2025-30 period represent the next phase in a journey that began with our 2017 Future Network Strategy[35] and build on the successful execution of the plans set out in our 2020-25 Regulatory Proposal[36] and our Distributed Energy Transition Roadmap[37].

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. We have introduced cost-reflective tariffs, begun the process of shifting of hot water loads to the daytime, improved voltage management across the network, developed systems to support Smarter Homes and, most importantly, successfully implemented Flexible Exports.

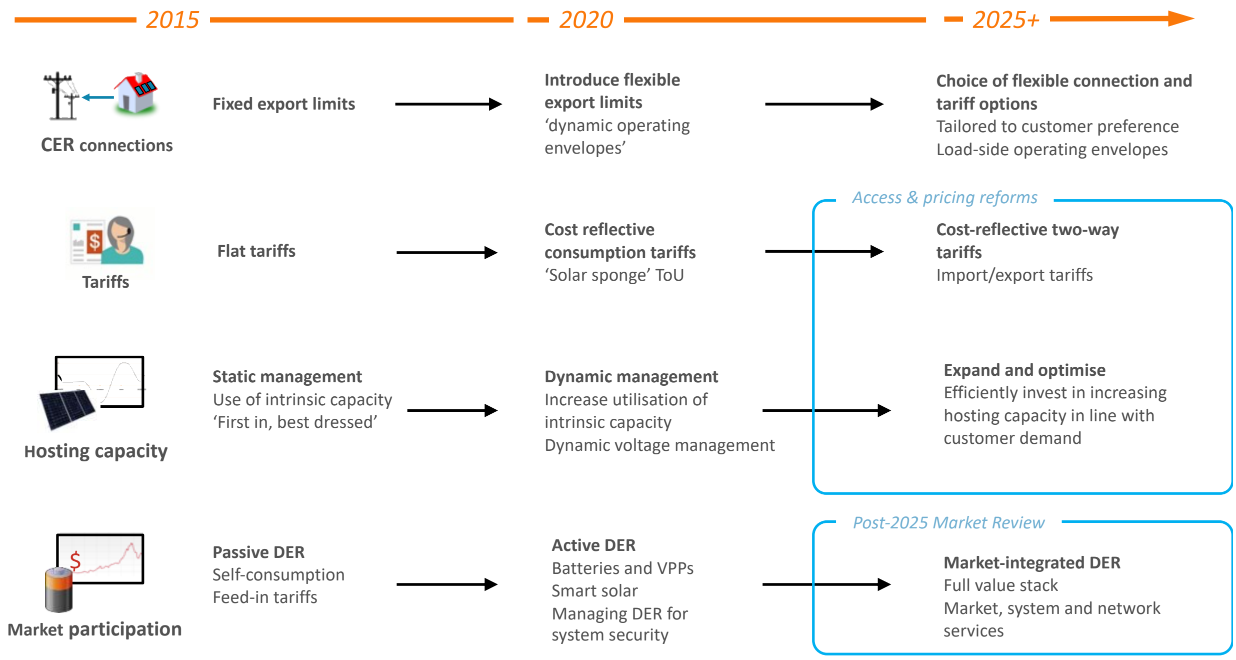
As we look towards the crucial second half of the decade on South Australia's pathway to a net zero-carbon electricity system by 2030, our 2025-30 Regulatory Proposal builds on these foundations by extending DOEs to support flexible loads, increasing visibility of our LV network, continuing the transition to more cost-reflective tariffs (including the introduction of export tariffs) and 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 progression is summarised in the figure below.

[35] SA Power Networks, *Future Network Strategy 2017-2030*, supporting document 5.17 to our 2020-25 regulatory proposal, accessed at [www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/proposal]. Updated in 2020 to develop our *Network Strategy 2020-2030*, included as document 5.7.1

[36] SA Power Networks, *2020-25 Regulatory Proposal, An overview for South Australian electricity customers*, available at [www.aer.gov.au/system/files/SAPN%20-%20%20Electricity%20Distribution%20Proposal%202020-2025%20-Overview%20-%20January%202019_0.pdf], accessed 26 January 2024.

[37] SA Power Networks, *Distributed Energy Transition Roadmap 2020-2025*, available at [www.sapowernetworks.com.au/future-energy], accessed 26 January 2024.

Figure 12: Elements of our CER integration journey 2015 to 2025+

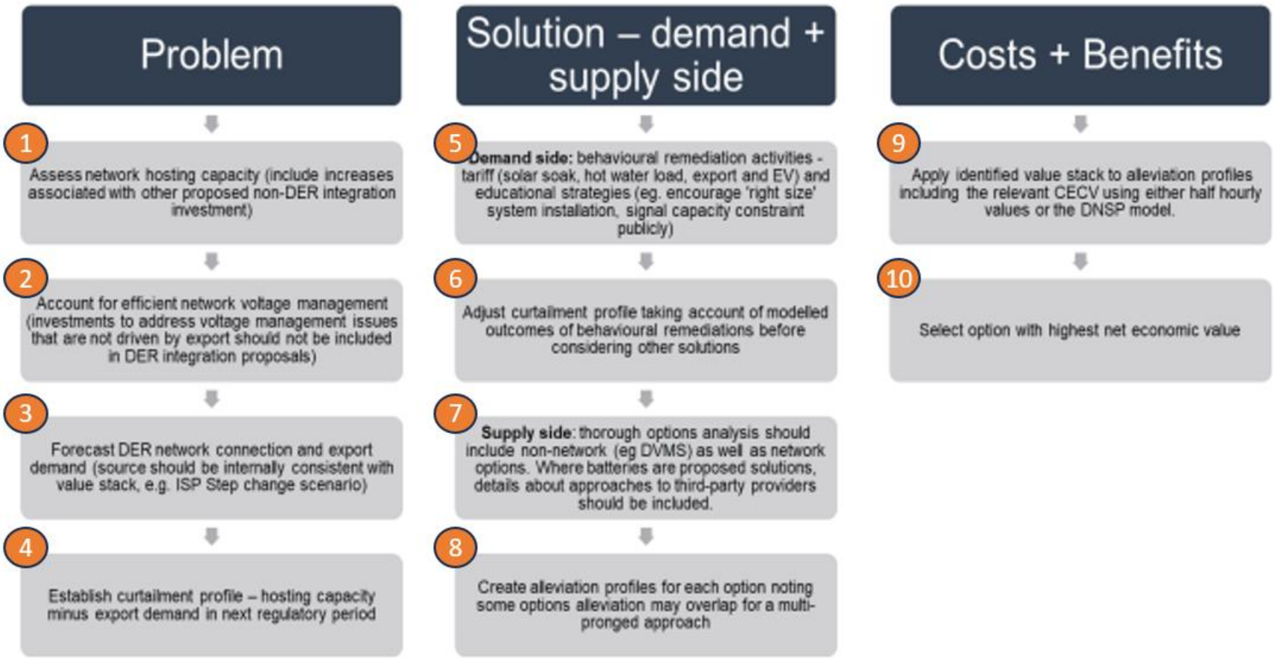


A. Appendix A – alignment with the AER's DER integration expenditure guidance note

A.1 Process for developing our CER integration investment proposal

Figure 13 below is from the AER's DER integration expenditure guidance note[38] and illustrates the AER's expectations as to the methodology to be used, and the factors that should be taken into account, in developing a CER integration plan. Our approach is aligned with this guidance, as summarised by reference to each numbered item below.

Figure 13: The AER's recommended process for developing CER integration investment proposals. Source: Figure 1.1 in the DER integration expenditure guidance note, numbers added.



<u>Problem</u>

1. **Assess network hosting capacity**

   We estimate hosting capacity individually for each of the 70,000+ LV transformers in our network for each year from 2025-2050 as follows:

   - current (2023) hosting capacity is estimated using a combination of electrical modelling and smart meter data analytics from our available sample of around 23,000 smart meters;
   - hosting capacities are then adjusted for each year from 2025-2030 to take into account:
     - the impact year-on-year of the underlying trend of improving compliance to AS4777 Volt-VAr settings as solar inverters are replaced or upgraded over time;
     - the additional annual forecast increase in AS4777 compliance levels resulting from our proposed 2025-30 CER Compliance program; and

[38] AER, CER integration expenditure guidance note, June 2022, available via: [www.aer.gov.au/industry/registers/resources/reviews/distributed-energy-resources-integration-expenditure-guidance-note/final-decision], accessed 24 January 2024.

   - the increase in effective hosting capacity arising from improved network visibility due to our proposed 2025-30 Network visibility and LV model improvement program.

2. **Account for efficient network voltage management**

   Individual LV transformer hosting capacities are also adjusted to account for the impact of additional substation LDC works currently planned for completion prior to 2025.

3. **Forecast CER network connection and export demand**

   We use AEMO's ISP as our primary source for CER uptake forecasting (solar, batteries and EVs), with the Step Change scenario as the central case on which our expenditure proposal is based. We engaged consultants Blunomy (formerly Enea) and Evenergi to build models to map AEMO's state-wide forecasts to postcode level using demographic data and other inputs such as saturation points for rooftop PV. These postcode-level forecasts are then aggregated to provide individual CER uptake forecasts for each LV transformer area.

4. **Establish curtailment profile**

   Our LV Planning Engine (**LVPE**) calculates net load flow for every LV transformer for every 30 minute interval from 2025 to 2050 using:

   - CER uptake forecasts;
   - solar irradiance and temperature data sourced from the Bureau of Meteorology for a representative year;
   - representative temperature-dependent load profiles for households and C&I customers based on an analysis of customer smart meter data, including customers with and without electric hot water, scaled on a per-NMI basis based on individual customer usage data;
   - representative load/generation profiles for batteries based on smart meter data, including VPP customers; and
   - representative EV charging profiles developed by consultant Evenergi.

   The load flow model has been tested and calibrated against actual load data from a sample of LV transformer monitors. It takes around 21 hours to complete a load flow estimation for the whole network for 2025-50 running on Microsoft's Azure cloud compute service.

   The LV Planning Engine then uses the calculated load flow in combination with the annual per-transformer hosting capacity estimates to calculate an individual 25-year curtailment profile for every LV transformer that includes every 30 minute interval from 2025-2050.

   This curtailment profile assumes that Flexible Exports is the standard connection option for all new solar customers by July 2025, so solar customers will generally only be curtailed by the minimum amount required to maintain quality and security of supply during times when hosting capacity is exceeded, rather than being curtailed year-round due to static export limits.

Solution – demand + supply side

5. **Demand side: behavioural remediation activities**

   The load profiles used in the load flow analysis described above incorporate the effects of several demand-side activities:

   - we model the ongoing shifting of load in response to TOU tariffs by using two versions of each load profile used in the load flow analysis, both based on actual customer meter data, one derived from meter data from customers that do not yet have TOU tariffs and the other based on data from customers that already have TOU tariffs. These are blended in the model in proportion to the forecast ratio of customers with TOU tariffs vs. flat tariffs in each year, based on a forecast smart meter rollout rate aligned with the accelerated rollout by 2030 proposed in the AEMC's recent metering review. The forecast increase in tariff response has the effect of progressively increasing underlying daytime load and reducing peak demand through the 2025-30 period;

- similarly, since our 'solar sponge' controlled load tariff was introduced in 2020 we have observed retailers start to shift hot water loads from overnight to the daytime in response, for those customers where they are able to change the timing remotely via a smart meter. Our model assumes that this continues, and we assume that all hot water customers ultimately transition from the pre-2020 overnight hot water profile to a profile based on actual meter data from the retailer that has been most proactive in this regard to date, which has a significant portion of hot water load shifted to the solar sponge period. As above, the pace of this transition is based on an assumed accelerated smart meter rollout through the 2025-2030 period;
- the EV charging profile developed by consultant Evenergi combines expected residential and commercial charging behaviours based on the latest available studies of EV charging. This profile includes daytime charging loads commensurate with the levels of daytime charging observed when EV owners have their own solar and/or 'solar sponge' tariff incentives; and
- finally, the base case for our CER integration expenditure proposal includes annual adjustments to load profiles to reflect the expected impacts of our proposed demand flexibility program, which seeks to use DOEs on the demand side to further shape and shift loads to reduce peak demand and increase alignment of daytime loads with solar output.

6. **Adjust curtailment profile taking into account modelled outcomes of behavioural remediations before considering other solutions**

   As described above, the LVPE considers the forecast impacts of behavioural remediations due to:

   - the continued transition to TOU tariffs;
   - our proposed 2025-30 CER compliance program; and
   - our proposed 2025-30 demand flexibility program.

   All these effects are modelled during the load flow analysis that produces the initial curtailment profile, which is then used to determine the need for capacity augmentation investment. Thus our model only proposes network solutions in areas where the above behavioural responses and non-network solutions are not sufficient to maintain export service performance in the 2025-30 period.

7. **Supply side: thorough options analysis should include non-network as well as network options**

   Our analysis includes the following non-network solutions:

   - flexible Exports (dynamic export limiting);
   - 'solar sponge' TOU tariffs;
   - our CER compliance program; and
   - our demand flexibility program.

8. **Create alleviation profiles for each option**

   'With and without' analysis is used to create alleviation profiles for the above non-network solutions to quantify benefits using the CECV. Our LVPE then considers the additional investment required in capacity augmentation in the LV network required to deliver different export service level options through the 2025-30 period, and creates the alleviation profiles associated with each of these options.

Costs + benefits

9. **Apply identified value stack to alleviation profiles including the relevant CECV**

   We consider the following in valuing alleviated curtailment:

   - the 30-minute CECV values;
   - the value of avoided generation capacity investment, modelled as an additional 30-minute value stream similar to the CECV. This is derived using an economic model from consultant Houston Kemp, based on a forecast curtailment profile produced by the LVPE.[39]

10. **Select option with the highest economic value**

    For each export service level option, the LVPE determines the series of investments with the highest net present value.

A.2 Supplementary information for the CER integration strategy

The AER's DER integration expenditure guidance note provides specific guidance on the information that should be included by a DNSP to supplement its CER integration strategy. The table below summarises where this information is provided.

Table 4: Information provided to supplement our CER integration strategy

Information item	Where included
Network voltage analysis	5.7.4 Business case: CER integration 5.7.9 CER integration modelling methodology
CER penetration forecasts for the electricity distribution network over the medium to long term (at least 10 years) and the expected forecast demand for export services on network.	5.7.9 CER integration modelling methodology 5.7.12 DER uptake forecasts, Final methodology report (Enea consulting) 5.7.13 GridFleet SAPN network-wide electric vehicle modelling, Methodology and assumptions report (Evenergi)
Evidence of how DNSPs will structure their tariffs to meet the forecast increase in demand for export services (supported by consumer behaviour modelling). It is our expectation that the use of two way pricing, including incentive pricing like solar sponge, EV charging and hot water load, will go a long way in matching the demand for export services. DNSPs should demonstrate how their proposed pricing structures will manage the demand for consumption and export services and make best use of existing network hosting capacity.	Section 4.2.1 in this document Attachment 18 – Tariff Structure Statement – Part A Attachment 19 – Tariff Structure Statement – Part B

[39] The methodology utilised by HoustonKemp to derive the value associated with avoided export capacity investment is described in their Avoided Generation Investment report which forms attachment 5.7.13 of our regulatory proposal.

Information item	Where included
A clear summary of the various elements of CER integration expenditure, in terms of augmentation, ICT capex and opex. Where the DNSP has identified deferred augmentation and/or replacement expenditure as a benefit associated with its proposed investment, it should demonstrate that its forecast of augmentation and/or replacement expenditure has been adjusted in a consistent manner.	Section 5 in this document Section 6 in this document 5.7.3 Business case: CER Compliance 5.7.4 Business case: CER integration 5.7.5 Business case: Demand flexibility 5.7.6 Business case: Network visibility
Details of the DNSP's plan (if any) for the implementation of dynamic operating envelopes (DOEs),which may include the timing of trials, methods for capacity allocation and consumer engagement.	5.7.4 Business case: CER integration 5.7.5 Business case: Demand flexibility
Details of activities undertaken and actual expenditure in the current regulatory period to manage CER integration.	Section 4 in this document Section 7 in this document 5.7.3 Business case: CER Compliance 5.7.4 Business case: CER integration 5.7.5 Business case: Demand flexibility 5.7.6 Business case: Network visibility
Transparent references to expenditure items in the reset RIN	Appendix C in this document

B. Appendix B – alignment with the AER's draft interim export limit guidance note

B.1 CER integration

In its draft interim export limit guidance note[40], released in November 2023, the AER proposes that DNSPs should include commentary in their CER integration strategies that includes:

- *a holistic overview of the different initiatives that the DNSP is seeking to take to support the efficient integration of CER, and a summary of the identified CER integration problem that different initiatives are aimed at addressing, explaining how the impact of complementary measures (such as two-way pricing, voltage management, network visibility and use of export limits) have been taken into account in determining the DNSP's proposed expenditure*

- *how benefits have been apportioned to each program or project, where an investment is likely to deliver multiple benefits to different programs or projects*

- *the DNSP's approach and rationale for setting export limits (basic, static, and flexible) and how this relates to, and is consistent with, the DNSP's capacity allocation methodology*

- *how the DNSP has considered the use of other complementary tools, such as two-way pricing, in setting export limits.*

Our CER integration strategy document (this document) and the associated business cases align with this guidance, including detailed commentary on the matters above.

The interim guidance note also includes the figure below to illustrate potential options for managing network capacity that DNSPs should consider:

Figure 14: The AER's summary of potential options for managing network capacity, from Figure 6 in the Interim export limit guidance note[35]

Least expensive

Tool	Description
Cost reflective prices	Export tariffs signal to customers the additional network costs associated with relieving export constraints. If customers respond by self-consuming or investing in energy storage, future augmentation costs can be avoided or deferred.
Compliance and awareness	Many solar PV inverters are non-compliant with technical standards, which may require DNSPs to set conservative static export limits. Compliance activities, such as introducing commissioning sheets, are relatively low cost and will help to ensure that new or replacement solar PV inverters are compliant with technical standards. Better inverter compliance with technical standards will reduce the need for conservative static export limits and is a key enabler for the successful implementation of flexible export limits.
Voltage management	Adjusting transformer tap settings, phase balancing and dynamic voltage management are examples of activities to manage voltage and reduce voltage-related export curtailment.
Network visibility	Network visibility provides better knowledge about hosting capacity. Over the coming years, DNSPs are likely to get improved access to smart meter data following recent recommendations from the AEMC's smart metering review. This allows DNSPs to rely less on estimation and better target network investments, allowing them to offer higher static export limits which reflect the true state of the network.
Flexible export limits	Allows DNSPs to maximise existing hosting capacity. They may be simple (feeder level) or sophisticated (household level) and are generally preferable to augmenting the network to increase hosting capacity (dependent on network visibility and the level of investment in ICT that is necessary).
Network augmentation	Investments to increase network hosting capacity may be justified if they provide net economic benefits and other credible investment options have been considered.

Most expensive

[40] AER, *Interim export limit guidance note – for consultation*, November 2023, accessed at https://www.aer.gov.au/system/files/2023-11/Draft%20export%20limit%20interim%20guidance%20note%20-%20November%202023.pdf

Regarding the above figure, the guidance note states:

> *Some of the options outlined in Figure 6 are also key enablers for the successful implementation of flexible export limits. For example, implementing flexible export limits requires network visibility and certainty that consumer energy resources are compliant with technical standards. Therefore, these activities may be complementary to flexible export limits rather than substitute options for managing network capacity*

As outlined in section 4 above, our strategy and our plans for managing network capacity in 2025-30 incorporate all the elements shown in the AER's figure and align with the AER's guidance. In addition, we are proposing a specific work program aimed at activating greater flexibility on the demand (load) side through DOEs, flexible connections and new incentives to help manage peak demand and to facilitate the shifting of loads to match times of high solar production.

B.2 Capacity allocation

The AER's guidance note also proposes that:

> *DNSPs should include commentary, as part of their CER integration strategies, on how their capacity allocation methodology reflects the capacity allocation principles and how it has been shaped by consumer and stakeholder feedback.*

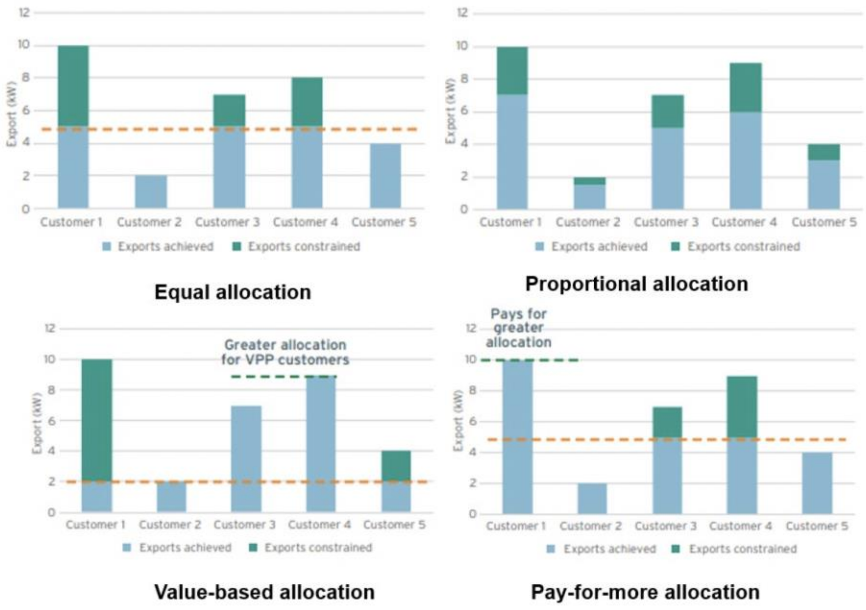
In the sections below we provide an overview of our capacity allocation methodology and then show how this aligns to the AER's capacity allocation principles.

B.2.1 Our capacity allocation methodology

The AER's interim export limit guidance note makes reference to four different capacity allocation models that DNSPs could use to allocate network capacity. These models were developed by the Dynamic Operating Envelopes Working Group convened under Australian Renewable Energy Agency's (**ARENA**) Distributed Energy Integration Program (DEIP)[41] and are shown below.

Figure 15: Capacity allocation models, from Figure 5 in the interim export limit guidance note

[41] DEIP Dynamic Operating Envelopes Working Group, *Outcomes Report*, March 2022, available at: [www.arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf], accessed 26 January 2024.



Our Flexible Exports system uses the equal allocation model to allocate available export capacity to small customers, which we also refer to as the 'waterline' model. In this approach all flexible export customers downstream of a constraint receive the same dynamic export limit, regardless of the size of system they have installed. SA Power Networks and our stakeholders consider this the most equitable and appropriate allocation model for small customers because all small customers connect under the same standard connection agreement, as set out in our Model Standing Offer (**MSO**), have systems that are similar in size (typically 5 – 10 kW), and are treated equally with respect to their export tariffs. The exceptions are:

- customers that connected solar prior to the availability of flexible exports in their area will have received a legacy static export limit (5 kW per phase under current rules). These customers will continue to receive an allocation based on the static limit that applied at the time of their connection, or the size of their inverter, whichever is lower. In most cases these customers' equipment is unable to respond to a flexible export DOE because it does not support the CSIP-AUS communications standard. Customers that connected under a static 5 kW export limit but do have equipment able to support CSIP-AUS are able to opt in to flexible exports when it becomes available in their area should they choose to do so; and

- customers who are in a flexible exports area but elected to connect with a 1.5 kW static limit instead of the 1.5 – 10 kW flexible limit. These customers will receive a static allocation of 1.5 kW, reflective of the intrinsic hosting capacity of the network that they pay for through their consumption tariffs.

Note that although all flexible customers receive the same limit with the equal allocation model, it can be the case that not all customers in a constrained area have systems that are big enough to reach the limit – e.g. 'Customer 2' in Figure 15 has a 2 kW system and receives a limit of 5 kW. In this case we do not 'reserve' capacity for those customers that cannot use it, as this would be inefficient. Our goal is to allocate all available network capacity to be used and we take into consideration the mix of system sizes in the area when calculating the limit.

At the time of writing, our flexible exports connections are only available to small customers. We intend to extend this to include customers with larger embedded generators (30 kW – 200 kW) by December 2024. While the equal allocation model is appropriate for allocating capacity between small customers, many stakeholders consider that the proportional allocation model, in which all customers are curtailed by the same percentage of their connected capacity (which we refer to as the 'linear' model), is more appropriate and equitable for allocating capacity between customers with larger generators. This is because these customers can have systems with a broad range of sizes and have paid varying amounts to connect to the network, depending on the size of their system and where they are connected. As we roll out flexible exports to include larger embedded generators, and to areas that contain a mix of large and small embedded generators, we will move to a hybrid, or 'tiered', approach that combines the proportional allocation method for large customers with the equal allocation method for small customers.

The AER's interim guidance note also notes that there are different levels within the network at which capacity could be allocated, from network-wide (all customers) down to per-customer. Our approach is to calculate hosting capacity and allocate capacity at the local LV area, i.e. the area served by a single LV distribution transformer. This is the level of the network at which export constraints typically occur and treating each LV transformer area separately provides for the most granular and efficient allocation of capacity in our view.

B.2.2 Alignment with the capacity allocation principles

The table below lists the AER's capacity allocation principles and how our methodology aligns to them. Note that for the first two principles we have included the AER's proposed changes to the wording of the original DEIP principles[42], as suggested in the interim guidance note.

Table 5: How our capacity allocation methodology aligns with the AER's capacity allocation principles

Capacity allocation principle	How our methodology aligns
1. DNSPs are responsible for setting export limits. The calculation methodology used to determine the limits should be transparent, subject to stakeholder consultation and informed by network hosting capacity analysis. Static export limits should not be set arbitrarily low.	Our approach to capacity allocation, as with our approach to all aspects of our transition from static to flexible exports in South Australia, has been (a) developed over several years in collaboration with a broad range of stakeholders and (b) tested and refined through field trials with open and transparent feedback. Key stakeholder working groups involved in the co-design of our flexible exports offer and capacity allocation methodology since 2019 include: • our Connections Working Group (**CWG**) comprising a cross-section of South Australian customers including commercial-scale solar customers; • our Solar Industry Reference Group (SIRG), convened specifically to give the South Australian solar industry a voice in the development of flexible exports; • our DER Integration Working Group (**DERIWG**) a national working group of experts and senior leaders from the DER industry, market bodies and customer representatives; • the DEIP Dynamic Operating Envelopes Working Group, of which we were a member, where we contributed to the development of the capacity allocation principles and four capacity allocation models; and • the South Australian Government's Dynamic Exports Committee, which brings together ourselves, energy retailers, generators, equipment manufacturers, representative bodies, AEMO, solar installers and the Government to collaborate on the transition to flexible exports in South Australia as part of the Government's broader plan to increase CER uptake, promote decarbonization and ensure security of the state's power system. Our approach has been refined through our ARENA-funded Flexible Exports for Solar PV field trial[43], which ran from 2021 to 2023. This trial was undertaken in partnership with leading inverter manufacturers Fronius, SMA and Solar Edge, technology platform vendor SwitchDin and Victorian DNSP Ausnet Services, and included comprehensive Customer Experience research conducted by SEC Newgate. As well as sharing learnings and technical details of our approach and methodology through our trial, we have developed a comprehensive set of online resources, fact sheets and videos for customers and solar resources to support them in understanding how flexible exports works, available on our web site[44]. Our standard offer, which allows customers to choose between a fixed export limit of 1.5 kW per phase or a flexible one of 1.5 kW – 10 kW has been informed by detailed network hosting capacity analysis, initially undertaken during the development of our 2020-25 regulatory proposal by consultant EA Technology using PowerFactory modelling of sample parts of our network and subsequently

[42] The principles were originally developed by the Dynamic Operating Envelopes Working Group convened under ARENA's Distributed Energy Integration Program (DEIP), of which SA Power Networks was a member, and published in the Working Group's March 2022 *Outcomes Report*, available at: [www.arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf], accessed 26 January 2024.

[43] See [www.sapowernetworks.com.au/future-energy/projects-and-trials/flexible-exports-for-solar-pv-trial], accessed 26 January 2024.

[44] See [www.sapowernetworks.com.au/industry/flexible-exports], accessed 26 January 2024.

Capacity allocation principle	How our methodology aligns
	refined using an analysis of a sample set of smart meter data. Details of this methodology are included in our CER integration business case and supporting documents[45]. Our static export limit of 1.5 kW has not been set arbitrarily, but is based on this hosting capacity analysis, which has established that 1.5 kW per phase is reflective of the intrinsic hosting capacity of our network.
2. Allocation should seek to maximise the use of network export hosting capacity while balancing customer expectations of transparency, cost and fairness. It should take into consideration complementary measures such as two-way pricing.	We have described of our capacity allocation methodology in section B.2.1 above and how it seeks to balance customer expectations of transparency, cost and fairness. The calculation of available capacity that is used to generate the flexible export limit is performed on a rolling basis using a load flow model at each LV transformer area. This uses load profiles for small and large customers that are derived from real customer data and hence incorporate behavoural effects such as tariff response. This currently includes the effect of one-way TOU tariffs but will reflect the effect of two-way tariffs when we introduce export pricing from mid 2025.
3. Capacity allocation can initially be based on net exports and measured at the customer's point of connection to the network.	Our flexible export limits apply to net export at the customer connection point.
4. Capacity should be allocated to small customers irrespective of the size or type of customer technology (for example, solar or batteries) at the customer premises.	Our flexible export limits apply to net export at the customer connection point irrespective of the mix of customer technology at the premises. As described in section B.2.1 above, all small customers within the same LV area receive the same export limit regardless of the size of their system. For larger customers, a proportional allocation method will be more appropriate.
5. In the near term, flexible export limits should be offered on an opt-in basis with capacity reserved only to make good on legacy static limit connection agreements, with efficient incentives provided for customers to transition to flexible export limits over time.	Our flexible export limits are offered on an opt-in basis, with new solar customers having the option to choose a 1.5 kW static limit if they prefer, reflective of the intrinsic hosting capacity of the network. As described in section B.2.1 above, our capacity allocation methodology reserves sufficient capacity to serve customers on legacy static limits, and does not reserve capacity for customers that cannot use it. Customers who are replacing or upgrading an existing system in South Australia must install one that is compatible with flexible exports (under SA Government Smarter Homes regulations) and generally have a strong incentive to choose the flexible 1.5 kW – 10 kW limit over the static 1.5 kW limit as this will provide a much better financial outcome in terms of feed-in tariff revenues even in congested areas. The 10 kW upper bound for export limits under our flexible exports connection offer compared to the legacy limit of 5 kW also provides legacy customers an incentive to transition where they wish to expand the size of their system.

[45] 5.7.4 Business case: CER integration

C. Appendix C – related expenditure items in the reset RIN

The table below shows the mapping of expenditure items in our CER integration business cases to the reset RIN.

Note that the dollar figures included here are in real June $2022, for consistency with the dollar basis used in the business cases and elsewhere in this document, whereas the figures in the RIN are in real $2025.

Expenditure item	Capex $2022 $ million	Opex $2022 $million	Reset RIN categories
5.7.3 CER compliance			
DER007 - DER Compliance	5	2.2	7.8.1 OPEX FOR PROVISION OF EXPORT SERVICES *Other opex* 7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Other capex*
5.7.4 CER Integration			
DER001 - LV Management	4.2		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Other capex*
DER002 - Hosting capacity - Voltage - HV	9.4		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Other capex*
DER015 - Flexible Exports System Maintenance and Scaling	2.4	3.8	7.8.1 OPEX FOR PROVISION OF EXPORT SERVICES *Other opex* 7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *ICT capex*
DER016 - Other DER IT Supporting Systems	2.6		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *ICT capex*
DER018 - Low Voltage Management - Export Capacity	42.2		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Other capex*
5.7.5 Demand flexibility			
DER004 - Demand Flexibility - Load DOEs	6.7		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *ICT capex*
5.7.6 Network visibility			
DER005 - Smart Meter PQ Data and Visibility Platform	4.2	6.0	7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Network monitoring capex* 7.8.1 OPEX FOR PROVISION OF EXPORT SERVICES *Other opex*
DER013 - SCADA Metering to Feeders	1.1		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Network monitoring capex*
OPT12 - Data Improvements Visibility	2.7		7.8.2 CAPEX FOR THE PROVISION OF EXPORT SERVICES *Other capex*
Totals	**80.5**	**12**	