Business case: demand flexibility

2025-2030 Regulatory Proposal

Supporting document 5.7.5

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SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CAB	Community Advisory Board
Capex	Capital expenditure
CECV	Customer Export Curtailment Value
CER	Customer Energy Resources
CSIP-AUS	Common Smart Inverter Profile – Australia. The Australian profile for the IEEE2030.5 communication standard for inverters that enables flexible exports / dynamic operating envelopes
DEIP	Distributed Energy Integration Program (an ARENA program)
DER	Distributed Energy Resources
DERIWG	Distributed Energy Resources Integration Working Group
DERMS	Distributed Energy Resource Management System
DOE	Dynamic Operating Envelope
DNSP	Distribution Network Service Provider
DSO	Distribution System Operator
ENA	Energy Networks Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunity
EV	Electric Vehicle
EVC	Electric Vehicle Council
FTA	Flexible Trading Arrangements
HEMS	Home Energy Management System
ISP	Integrates System Plan
LV	Low voltage
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
Opex	Operating expenditure
OPCL	Off-peak Controlled Load
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 the business case for our 2025-30 Demand Flexibility program, a program of work focused on managing demand and increasing network utilisation by enabling and encouraging flexibility on the demand side.

1.2 Expenditure category

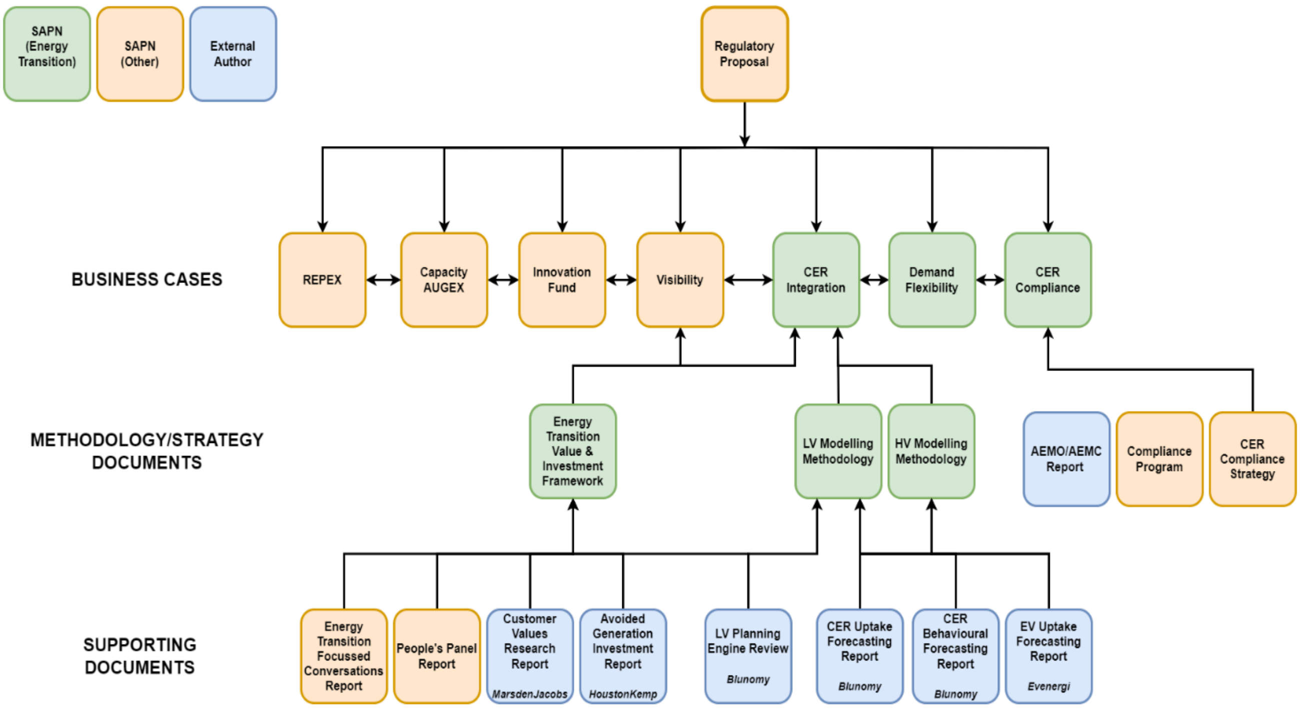
- Non-network capex

1.3 Related documents

Table 1: Related documents

Title	Author	Version / date
5.4.2 - Augex Capacity - Business case		
5.7.4 - CER Integration - Business Case		
5.7.6 - Network Visibility - Business Case		
5.7.7 - Innovation Fund - Business case		
5.7.15 - CER Integration Strategy - Strategy		

Figure 1: Related documents



2 Executive summary

Overview

This document sets out the business case for our 2025-30 Demand Flexibility program, a program of work focused on managing demand and increasing network utilisation by enabling and encouraging load flexibility. The program has a capital cost (**capex**) of **$6.7 million**[1] in the 2025-30 Regulatory Control Period (**RCP**).

Drivers for change

The Australian Energy Market Operator (**AEMO**) is forecasting that the 2025-30 RCP will see an increase in peak demand driven by Electric Vehicle (**EV**) uptake and broader electrification, as well as a continued increase in daytime energy exports from increasing levels of rooftop solar.

A key part of our strategic approach to integrating Customer Energy Resources (**CER**) and managing peaks in both demand and export is to increase the level of demand-side participation, that is, shifting and shaping flexible loads to reduce load at peak demand times and, where possible, bring on load to soak up excess solar in the middle of the day.

Our proposed capital program

We propose to invest in 2025-30 in developing new systems and processes to enable 'Dynamic Operating Envelopes' (**DOEs**) on the demand (load) side. This will enable new customer offers, flexible connection arrangements and incentives for customers who elect to allow their flexible loads such as commercial and residential EV chargers, hot water systems, data centres or industrial loads to operate within a DOE.

The aim of these new connection offers and incentives is to activate a higher and more optimal level of demand response than is achieved via cost-reflective price signals such as time-of-use (**ToU**) tariffs alone, increasing daytime self-consumption of solar and reducing the risk of customer impacts due to network congestion.

The proposed program will build on foundational systems and capabilities developed in the 2020-25 RCP to support the transition to 'flexible exports' for rooftop solar. It will also build on learnings from our current demand flexibility trials, including our proposed 'Diversify' tariff trial for customers with smart home EV chargers.

Costs, benefits and options

The proposed program has a cost of $6.7 million in capex in the 2025-30 RCP and forecast quantified net present value of $6.7 million arising from:

- a reduction of unserved energy risk associated with peak demand events, estimated using the value of customer reliability (**VCR**); and
- a reduction in export curtailment resulting from additional daytime loads at times of peak export, estimated using the customer export curtailment value (**CECV**).

We also anticipate further benefits were not quantified, as described in this business case.

The proposed program was selected after an options analysis that considered several alternatives, two of which were examined in detail: a base case 'do nothing' option ('option 0'), and a more comprehensive program ('option 2'). Option 2 includes additional systems, interfaces and services for market participants such as virtual power plant (**VPP**) operators, as well as capabilities to facilitate potential new market models such as Flexible Trading Arrangements (**FTA**).

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1 Figures are in June $2022.

Option 2 received strong stakeholder support despite it having a higher forecast customer bill impact than Option 1 due to the higher costs involved, reflecting a strong desire among stakeholders that we should aim to maximise the opportunity to make use of demand flexibility in future. It was not selected as the preferred option, however, because we consider that the additional future benefits are uncertain at this time. Instead, we propose to include the development of these more advanced capabilities as a potential project that could be funded via our proposed Innovation Fund, which is the subject of a separate business case.[2]

Related expenditure

The demand flexibility program has links to the following expenditure items described elsewhere in our proposal:

- 5.4.2 - Augex Capacity - Business case;
- 5.7.4 - CER Integration - Business Case;
- 5.7.6 - Network Visibility - Business Case; and
- 5.7.7 - Innovation Fund - Business case.

3 Background

3.1 The scope of this business case

This document sets out the business case for our 2025-30 Demand Flexibility program, a program of work focused on managing demand and increasing network utilisation by enabling and encouraging load flexibility. This includes the development of new operational capabilities to help customers activate flexible resources like commercial and residential EV chargers, residential and grid-scale batteries, commercial and industrial loads, hot water and smart appliances.

Central to this work program is the development of 'flexible load' connection services for small and large customers. This involves extending the IT systems, technical standards, network capacity models and business processes that were developed to support flexible exports connections to support a full DOE for both import and export.

This business case also considers extending dynamic connection services and business processes to support the integration of DOEs with CER aggregators, VPP operators and retailers to support increasingly active participation of aggregated CER in the market, building on trials undertaken in the 2020-25 RCP.

This business case links to other related expenditure described elsewhere in our proposal:

- our network capacity augex program (5.4.2 – Augex Capacity - Business case);
- our proposed CER Integration program (5.7.4 – CER Integration - Business Case);
- our proposed Network Visibility program (5.7.6 – business case: network visibility); and
- our proposed Innovation Fund (5.7.7 - Innovation Fund - Business case).

3.2 Drivers for change

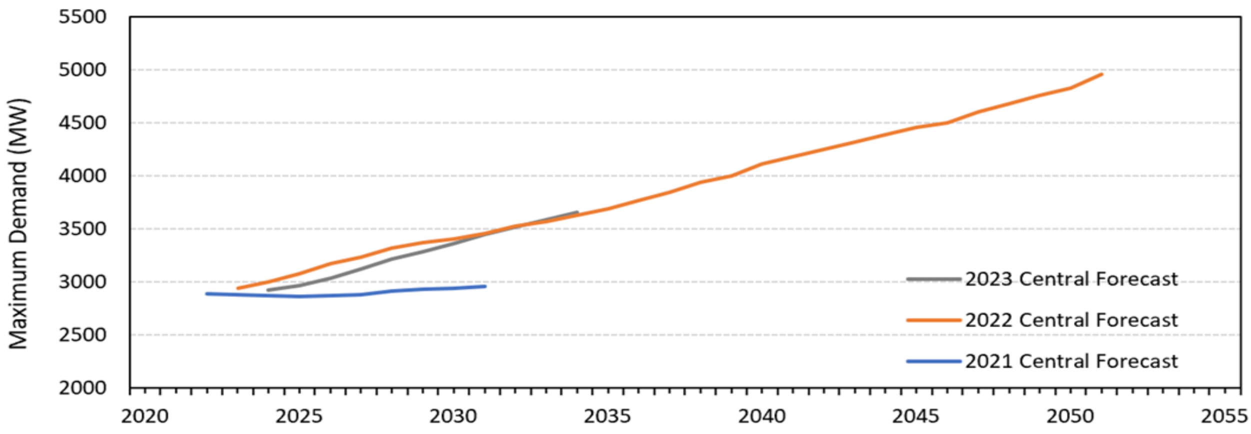
Over the last decade, summer peak demand in South Australia has remained relatively constant as the annual growth due to the increasing population has been offset by the continued uptake of rooftop solar and the

2 5.7.7 - Innovation Fund - Business case

increasing efficiency of homes and appliances. This is now changing, with AEMO's most recent forecasts predicting that South Australia is about to enter a new and sustained phase of peak demand growth, driven primarily by the transition to EVs and the broader shift to electrification for homes and businesses as the economy continues to decarbonise.

AEMO's SA 2022 state demand forecast[3] predicts that operational summer demand will increase at a Compounded Annual Growth Rate of 1.91% from 2022/23 to 2031/32. This is the most significant growth forecast for South Australia in the last decade[4].

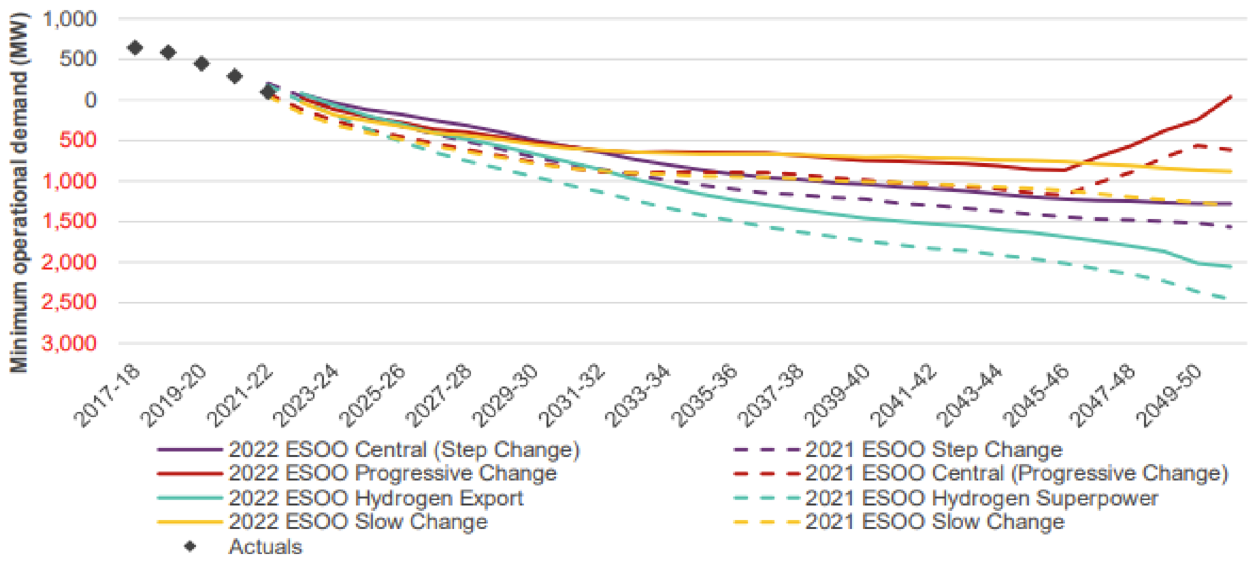
Figure 2 – SA Operational Demand (summer 50% POE central (step change) scenario)[5]



This forecast growth in peak demand is driving a corresponding increase in forecast network capacity augmentation expenditure (capacity augex) in the 2025-30 RCP when compared to the 2020-25 RCP, as detailed in our capacity augmentation business case (document 5.4.2).

At the same time as peak demand is forecast to grow, state-wide minimum demand is forecast to continue to decline rapidly, due primarily to the continued uptake of small-scale rooftop solar, as shown in Figure 3.

Figure 3 – SA Minimum Operational Demand (summer 50% POE central (step change) scenario)[6]



3 AEMO, *Electricity Statement of Opportunities 2022*

4 AEMO's 2021 forecast for the period 2021/22 to 2030/31 had a Compounded Annual Growth Rate of just 0.2 percent.

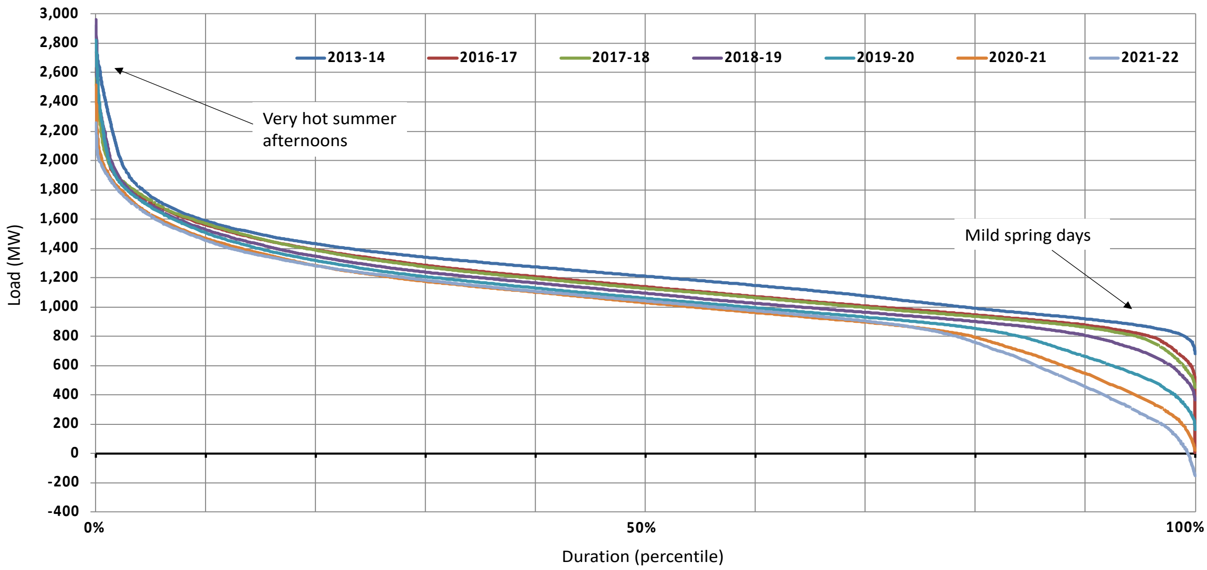
5 AEMO, *Electricity Statement of Opportunities 2022*

6 AEMO, *Electricity Statement of Opportunities 2022*

In the distribution network, this means that local daytime reverse power flows are forecast to exceed export capacity in parts of the network through the 2025-30 RCP, with constraints arising primarily at the Low Voltage (**LV**) transformer level. We propose to address this through a combination of dynamic export curtailment using flexible exports and targeted export capacity augmentation, as detailed in our CER integration business case (document 5.7.4).

The changing load on the network can be seen in Figure 4, which shows annual load-duration curves for our network from 2013 to 2022. The figure shows that, in the last decade, peak demand has remained relatively constant but the frequency of peak demand events has reduced slightly due to the impact of rooftop solar, which has eroded early evening loads, causing the summer evening peak to become narrower and later in the day. As the evening peak has now shifted outside solar hours, future growth in solar is not forecast to materially impact peak demand.[7] The impact of the growth in rooftop solar is also evident in reducing average demands and, in particular, in declining minimum demand and increasing periods of very low demand seen on the right side of the chart.

Figure 4 – SA Power Networks' network load-duration curves 2013-2022



The chart also shows that 70% of the time our network is operating at between 25% and 50% of its peak capacity, meaning that there is significant available capacity to accommodate growth in both load and generation outside of peak times.

A key part of our strategic approach to managing growth in both demand and export is to increase the level of demand-side participation, that is, shifting and shaping flexible loads to reduce load at peak demand times and, where possible, bring on load to soak up excess solar in the middle of the day. This can be achieved through a combination of price signals ('solar sponge' time-of-use tariffs as well as other price signals and incentives to reward flexibility) and smart controls, primarily the use of DOEs on the load side.

In combination, these measures can help reduce electricity costs for customers by increasing solar self-consumption and maximising access to off-peak tariff periods. They also increase market value by reducing the overall level of solar curtailment. Finally, they reduce network costs in the long term by increasing asset utilisation and reducing the need for traditional network capacity augmentation on the load and export side.

Just as the need for demand-side participation will increase through the 2025-30 RCP with growing demand on the network (both load and export) and greater intermittency of supply, so the opportunity will increase also, as customer devices become smarter and more connected, new energy management products mature

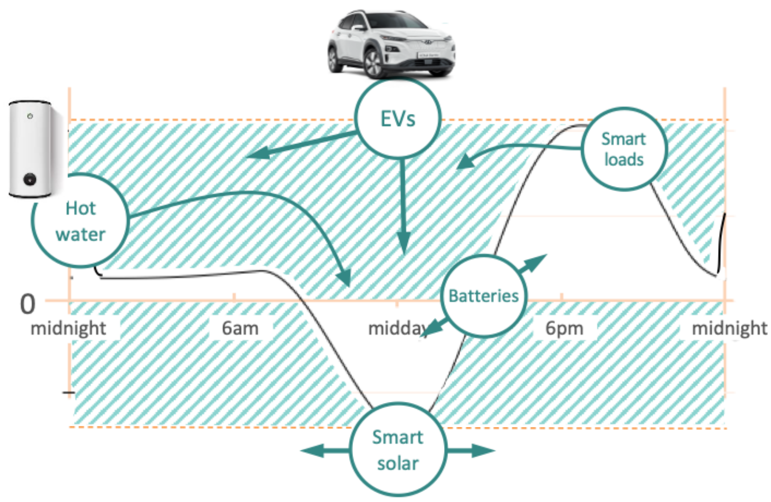
7 See AEMO's *Electricity Statement of Opportunities 2022*.

that can activate previously passive devices to shift load in response to price or other signals, and more customers transition to time-of-use tariffs as the rollout of smart meters accelerates.

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.

In the residential setting, hot water and EV charging loads present the most significant opportunities for load flexibility in the near term. These and other opportunities are illustrated in the context of a typical residential load profile in Figure 5 below.

Figure 5 – Hot Water and EV Load Shifting to soak up solar and avoid peak demands



As well as adopting individual smart devices in the home we expect increasing numbers of customers to engage with VPPs and other aggregation schemes to activate and optimise their flexible loads. We expect these kinds of CER aggregation schemes to continue to grow strongly and play a crucial role in the future market.

3.3 Our performance to date

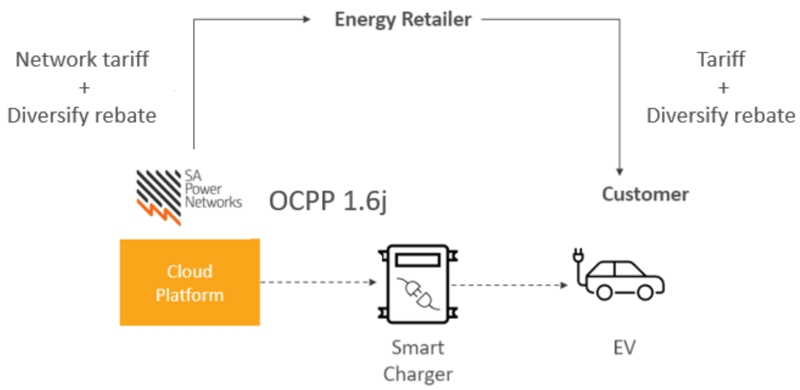
We are currently undertaking early-stage trials in this area to develop the concepts and establish the foundations for offering flexible load connection arrangements and load-side DOEs as part of our standard services in the 2025-30 RCP. Our activities to date include the following:

- we are launching a tariff trial for customers with smart EV chargers referred to as 'Diversify'[8]. In this opt-in trial a customer can receive a network bill credit of 33c/day ($120 annually) via their participating retailer if they elect to enrol their smart home EV charger to receive a daily maximum demand profile (a DOE) from SA Power Networks via the internet, so that charging load can be reduced when required to manage local network congestion at peak demand times. In this proof-of-concept trial we intend to use the OCPP 1.6j technical standard[9] for communications as this is widely supported in today's EV charger products, as shown in Figure 6. In line with industry trends, however, our goal for a production flexible load service is to support IEEE2030.5, the standard used for flexible exports, as this is a more general-purpose standard that supports all kinds of flexible load devices and home energy management systems (**HEMS**) and can be mapped to other device-level protocols as required;

8 SA Power Networks, *Trial Tariffs 2023-24*, accessed at download.jsp (sapowernetworks.com.au) .

9 OCPP is the Open Charge Point Protocol, a standard developed by the Open Charge Alliance that is widely used in EV charging equipment globally – see https://www.openchargealliance.org/protocols/ocpp-16/

Figure 6 – Diversify tariff trial concept



- we are working with IKEA's South Australian Microgrid[10] and SA Water's Zero Cost Energy Futures project[11], two significant initiatives pioneering the use of demand flexibility at a large scale in a commercial / industrial setting in South Australia;
- we are seeing increasing interest in the concept of flexible load connections from parties wishing to connect large, flexible loads such as community batteries, highway EV charging sites and data centres to the distribution network and we are actively engaging with these parties to explore opportunities to test solutions. Under such an arrangement, instead of paying for a network connection with enough 'firm' capacity to meet their expected maximum demand requirements at any time, a customer would have the option to reduce their network costs (via a reduced up-front connection cost and/or a reduced demand tariff) in return for operating their loads flexibly to avoid or reduce peak demand impacts. These customers would benefit from being able to draw their full load at times when the network is not constrained but would automatically reduce their load when directed to do so by a signal from SA Power Networks, ensuring the network is not overloaded at peak demand times. These kinds of connection arrangements can potentially increase network utilisation, avoid the need for capacity augmentation and save customers money. In the case of EV charging network operators seeking to connect large EV charging stations in rural areas, where network capacity is limited and the cost and work required to augment the network can be very high, we are exploring if this kind of arrangement can make a location viable that would otherwise be impossible, or accelerate the connection process by allowing a connection to proceed ahead of future capacity upgrades;
- we have partnered with Rheem/Solahart and retailer Simply Energy on an ARENA-funded trial to test the potential benefits of smart hot water systems that enable hot water loads to be shifted dynamically to optimise customer, network and market benefits. These kinds of systems can potentially assist customers in areas with high solar penetration to time their hot water loads to coincide with high-solar export periods, reducing reverse constraints and potentially deferring export capacity augmentation. This project also aims to test the integration of other flexible loads including pool pumps and air conditioners, as well as the interaction with home battery storage[12]; and
- we are planning a significant field trial to commence in 2024 and run over three years to explore how customers with different combinations of CER and smart appliances and varying levels of sophistication in terms of their home energy management capabilities can take advantage of demand flexibility. This trial will inform and help develop the technical standards, incentives and customer

10 See https://www.energymining.sa.gov.au/home/news/latest/ikeas-microgrid-switched-on

11 See https://www.sawater.com.au/water-and-the-environment/recycling-and-the-environment/energy-management-and-climate

12 See https://www.sapowernetworks.com.au/future-energy/projects-and-trials/smart-hot-water-control/

services that we offer in the 2025-30 RCP using the DOE capabilities developed under the program proposed in this business case.

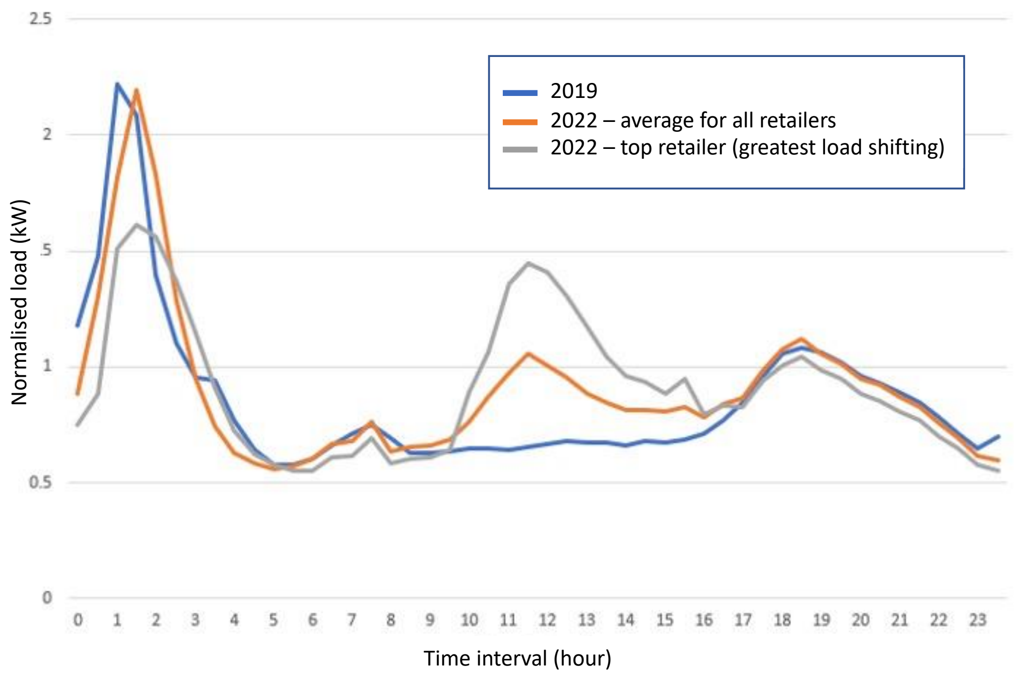
3.4 Industry practice

The most common example of the use of load flexibility by distribution network service provider's (**DNSPs**) is traditional off-peak controlled load (**OPCL**), where flexible loads like hot water and pool pumps are connected to a dedicated circuit that is switched according to a schedule set by the DNSP to keep these loads out of peak times. Many DNSPs are able to change the scheduling of these loads remotely, via 'ripple control' signals sent over the electricity network (e.g. in NSW and Queensland) or, in the case of Victoria, via smart meters.

In South Australia, controlled load was implemented using a lower-cost method based on a local time switch in the meter box, with no remote communications capability. With the gradual roll out of smart meters, however, retailers are progressively gaining the ability to remotely control and reprogram switching times.

In 2020 we relinquished control of scheduling 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 tariff, but also increasingly negative daytime wholesale prices in South Australia. Since then, several retailers have begun shifting overnight hot water loads 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[13]



DNSPs have also offered customers financial incentives to enrol their air-conditioners into demand-response schemes, using the AS4755 standard for local device control. In 2019, recognising the future importance of load flexibility, Energy Ministers set out a roadmap phasing in mandatory compliance with AS 4755 for electric water heaters, air conditioners, EV chargers and pool pump controllers, to come into effect between

[13] 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.

2023 and 2026 depending on the class of equipment. The South Australian Government subsequently adopted an alternative timeline which brought forward some of the proposed compliance dates.

While traditional controlled load and AS 4755-based demand response capabilities have proven effective over many years, as the energy system evolves, industry practice is shifting towards more modern technical standards and a more sophisticated and flexible approach to demand response.

Many industry stakeholders have the view that the connection of flexible loads to a separate physical circuit, even one that can be remotely controlled in near real time, is unduly limiting and should be phased out. It allows only for simple on/off control rather than more effective and more customer-friendly load shaping using a DOE, and the physical separation from other energy resources like solar and batteries that are not connected to the same circuit is an impediment to effective whole-of-home energy management.

Similarly, many stakeholders consider that the basic control capabilities of AS 4755 are no longer sufficient. If we are to achieve the potential benefits of demand flexibility in an increasingly dynamic electricity system we need to adopt more modern and flexible communications standards such as IEEE2030.5 that allow for DOEs and two-way communication, not just with individual devices but with home energy management systems and CER aggregators.

4 The identified need

As noted in section 3.2, after a decade in which peak demand has been flat or slightly declining in South Australia, AEMO is forecasting a renewed period of peak demand growth through the 2025-30 RCP and beyond. This growth is driven by increasing uptake of EVs and broader electrification of homes and businesses as carbon reduction efforts intensify in what will be a critical phase in the achievement of state and commonwealth 2030 decarbonisation targets. At the same time, state-wide minimum demand is forecast to continue to fall year-on-year as growth in rooftop solar continues.

From a network perspective, these factors combine to make the need for demand-side flexibility greater than ever, as this has the potential to enable a lower-cost pathway to meeting the forecast growth in demand for both load and export capacity than reliance on tariff price signals and traditional network augmentation alone.

Cost-reflective tariffs such as our 'solar sponge' time-of-use tariffs are a key tool for managing network capacity. They encourage changes in behaviour that lead to more efficient use of the network, on average, over the long term. Noting that tariffs are based on Long Run Marginal Cost methods (as prescribed under the National Electricity Rules (**NER**)) and intend to signal long-term cost drivers, tariffs alone cannot address short-run and/or localised peaks in demand.

Moreover, while time-of-use tariffs are a significant improvement over flat tariffs, they can produce behaviour that is sub-optimal. Taking EV charging as an example, a ToU tariff with an off-peak period beginning at midnight tends to result in a high percentage of night-time EV charging starting as soon as the tariff price changes, with charging loads concentrated in the 2-3 hours immediately after, whereas a smoother and more constant load through the whole night would be preferable from a network and market perspective and have no detriment to customers. With greater automation and sophistication of their flexible resources, including the use of load-side DOEs, customers can respond to tariffs more effectively and can also respond to other incentives and opportunities associated with local short-run constraints.

In considering responses to the forecast changes in demand on the network, and the potential opportunities afforded by emerging demand-side technologies, we considered the views of our customers and our regulatory requirements.

Through our stakeholder engagement program our customers expressed strong support for us investing in 'smarter' approaches to capacity management that enable, and reward customers for, flexibility on the demand side, where this can reduce the need for traditional network augmentation expenditure or minimise customer impacts from extreme peak demand events.

Regarding our regulatory obligations, the expenditure objectives in the NER[14] require us to propose expenditure for the 2025-3030 RCP that we consider is required to:

1. meet or manage expected demand for Standard Control Services, including both the supply of electricity and the export of electricity;
2. comply with all applicable regulatory obligations or requirements, including compliance with reliability and safety standards set by the jurisdictional regulators; and
3. to the extent that there are no applicable regulatory obligations or requirements, otherwise maintain the quality, reliability and security of supply and export services, and the safety of the distribution system.

The NER expenditure objectives also expect us to propose expenditure that is both *prudent* and *efficient*. To this end, the NER also make it clear that, where we can make investments in *modifying the drivers of network demand* to reduce network constraints, reduce risks associated with equipment failure or address power quality or system security issues then we should consider this.[15] If the forecast benefits of such investments outweigh the costs (taking into account any additional risks), then the investments are likely to be both prudent and efficient, and aligned with the long-term interests of customers.

This business case is concerned with specific investments intended to modify the drivers of network demand in the 2025-30 RCP, namely investments in systems and business processes to enable DOEs on the load side. This will enable and encourage greater demand-side participation, facilitate future tariff offers like our 'Diversify' trial based on DOEs, and enable future flexible connection arrangements for large commercial and industrial loads such as EV fast chargers.

The associated shifting of flexible loads out of peak demand times and into the solar day has a range of forecast benefits including reducing the customer impact of peak demand events, reducing future export curtailment, reducing costs to customers and reducing carbon emissions.

5 Comparison of options

We examined a range of possible investments that could be made in 2025-30 to facilitate demand flexibility in South Australia, using both a quantitative analysis of forecast future benefits versus costs and by engaging with customers via our stakeholder engagement program to assess the level of community support for investment in this area.

5.1 The options considered

The table below provides a summary of the options that have been considered in this business case.

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14 Paraphrased here, based on Clauses 6.5.6(a) and 6.5.7(a) of the NER

15 See, e.g., the AER's *Explanatory statement: Demand management incentive scheme*, accessed at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism

Table 2: Summary of options considered

Option	Description
The base case (Option 0)	The base case assumes no new investment in operational systems and business processes to enable demand flexibility or DOEs on the load side. This option is included here only as a counterfactual to provide a baseline for comparison of the other options
Option 1 – Basic services	Option 1 is a modest capital investment program to develop the systems and business processes to enable new tariffs, incentives and connection arrangements based on DOEs on the load side.
Option 2 – Advanced services	Option 2 is the same as option 1 but with additional investments in advanced data publication services for market participants (including near real-time interfaces for network state data), and additional staff to support these services.

5.2 Options investigated but deemed non-credible

In developing the options in this business case, we also examined two other potential work programs, described below.

Table 3: Summary of non-credible options

Option	Description
Smart meter replacement program for hot water customers	We considered providing a subsidy to electricity retailers to bring forward smart meter replacements for controlled load customers, to accelerate the process of transitioning all electric hot water load from the legacy fixed overnight time window to our current 'solar sponge' time-of-use controlled load tariff. Our current tariff provides a strong incentive for retailers to shift load to the daytime, which is made possible by the remote control capabilities of smart meters. We consider that the slow pace of the smart meter rollout is delaying the realisation of the significant potential benefits of shifting hot water loads to the daytime, and some kind of acceleration is needed. We excluded this from the options considered in this business case because: • it became apparent that the AEMC's review of the contestable metering market was proposing to recommend a rule change that would accelerate the rollout of smart meters with a target of 100% completion by 2030[16]. Under the AEMC's proposed approach DNSPs would have a role in developing the rollout plan and could make a case for prioritising cohorts such as controlled load customers, where efficient to do so. It now appears likely that this rule change will go ahead, and it should largely deliver the benefits we were hoping to achieve from a subsidy program; • in consultation, stakeholders had mixed views on the merits of DNSPs subsidising retailers to bring forward meter replacements, with some feeling strongly that this was something that the retailers should be doing anyway and it was not appropriate in the contestable metering market to expect customers to contribute to the cost of meter replacements via network charge; and • from a regulatory perspective, the arrangements by which a DNSP could contribute to the capital cost of a meter installation were unclear, given the prohibition on DNSPs owning assets beyond the connection point. Note: in our cost/benefit analysis we do consider the beneficial impacts of the ongoing transition to ToU tariffs, including modelling in our LV model the assumed impact of the AEMC proposed accelerated rollout.
Flexibility services	We considered undertaking a pilot project at the beginning of the 2025-30 period to deploy an on-line network services procurement platform in South Australia. This was motivated by the success of the Piclo

[16] AEMC, *Final report, review of the regulatory framework for metering services*, August 2023, accessed at https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services, accessed august 2023

Option	Description
procurement platform pilot	Flex platform now used by many Distribution System Operators (**DSOs**) in the UK to run open tenders and procure network support services (non-network solutions) from demand aggregators and other third-party providers[17], including both peak-shaving and demand turn-up services. During our stakeholder engagement program (see section 6.1 below for details of our stakeholder engagement process) this was included in the options canvassed with stakeholders via our Energy Transition Focused Conversation workshops. It was subsequently removed from the proposal carried forward to our People's Panel because: • during our Focused Conversations, support for this option was mixed. Some stakeholders were not supportive of including expenditure in our proposal for a pilot of this kind of platform in South Australia because the future benefits were unclear; and • we were unable to determine a satisfactory way to estimate and quantify future benefits at this time given that this kind of flexibility marketplace would be new to the National Electricity Market (**NEM**). Given the UK experience, we still consider that there may be merit in a pilot of a flexibility services platform like Piclo Flex in the 2025-30 timeframe, but in light of the above we think it is more appropriate to explore this idea further in the context of our proposed Innovation Fund, with a view to potentially partnering with one or more other DNSPs to share costs and learnings. Our proposed Innovation Fund is described in a separate business case (document 5.7.7).

5.3 Analysis summary and recommended option

To compare the options we undertook a quantitative 20-year Net Present Value (**NPV**) analysis of costs and benefits over the period 2025 to 2045. This analysis has considered the following quantified benefit streams.

Table 4: Summary of quantified benefit streams

Benefit	Description
VCR benefit (peak demand management)	This benefit reflects the avoided future risk of customer impact due to outages (typically load shedding) arising from the capability to manage peak demand events using DOEs. This benefit is quantified using the Value of Customer Reliability (VCR). As described in our capacity augex business case[18], our proposed network capacity augmentation program involves the deferral of approximately $90 million in capacity augmentation projects that would be required to resolve forecast peak demand constraints arising in the 2025-30 RCP, but where the associated investment is not considered efficient when assessed using a probabilistic risk-cost method using the VCR. For these constraints, it is more efficient to rely on load shedding to manage capacity exceedances when they arise because the cost to customers of the resulting unserved energy, calculated using the VCR and weighted based on probability of exceedance, is expected to be less than the cost of the network augmentation that would be required to avoid the load shedding risk. Our proposed capacity augmentation program has, therefore, a residual risk of around $12 million[19] in forecast VCR losses arising from load shedding. The demand flexibility program described in this business case aims to alleviate a portion of that risk and improve outcomes for customers. Where possible, peak demand constraints will be managed by curtailing or shifting flexible loads for customers that have opted-in to demand flexibility schemes (e.g. flexible connection arrangements for large EV chargers based on DOEs on the load side). The associated benefit is quantified as follows:

17 See: https://www.piclo.energy/
18 5.4.2 - Augex Capacity - Business case
19 $2022, present value of forecast VCR losses over 2025-2045 period.

Benefit	Description
	• estimate, in each year, the percentage of new loads driving forecast peak demand constraints that will be flexible, assuming our proposed demand flexibility program goes ahead; • re-calculate the residual VCR risk, applying a reduced VCR value to the forecast unserved energy associated with the flexible portion of the load at risk, reflecting the fact that the customer impact of curtailment of this portion of the load will be much lower than the impact on customers of involuntary unplanned outages that is valued in the VCR (as flexible customers have elected to allow that portion of their load to be curtailed during extreme peak events); and • the quantified customer benefit from the demand flexibility program is then the difference between the residual VCR risk assuming the flexibility program is in place and the risk without. Sensitivity analysis is used to allow for uncertainty in the input assumptions. Further details of the assumptions and sensitivities are included in Appendix B.
CECV benefit (export curtailment reduction)	This benefit reflects the reduction in future export curtailment arising from the increased shifting of loads to the middle of the day, calculated using a modified version of the Australian Energy Regulator's (**AER's**) 2023 Customer Export Curtailment Value (CECV) which also takes into account avoided generation investment benefits. Using DOEs in combination with time-of-use tariffs can increase the amount of load during the solar peak period by reducing the 'front-loading' of load at the start of the off-peak tariff period (10am) that otherwise occurs for flexible loads like hot water and EV charging, and by encouraging more optimal operation of battery charging and discharging to match photovoltaic (**PV**) generation and load. This benefit is quantified using 'with and without' analysis via our LV Planning Engine, to model the incremental reduction in export curtailment and incremental CECV benefits, of more optimal load shifting. Sensitivity analysis is used to allow for uncertainty in the input assumptions. Further details of the assumptions and sensitivities are included in Appendix B.

These and other non-quantified benefits are described further in the options comparison below.

5.3.1 Options assessment results

The table and chart below summarise the results of the comparison of options.

Table 5: Costs, benefits and risks of alternative options relative to the base case over the 20-year period, $m, $ June 2022 real. The Option 0 (Base Case) costs have been subtracted from all options.

Option	Costs		Benefits[20]			NPV[21]	Risk Level[22]	Ranking
	Capex[23]	Opex[24]	Capex	Opex	Customer			
Option 0 – Base Case	-	-	-	-	-	-	Medium	N/A[25]

[20] Represents the total capital and operating benefits, including any quantified risk reductions compared to the risk of Option 0 (base case), over the 20-year cash flow period from 1 July 2025 to 30 June 2045 expected across the organisation as a result of implementing the option.

[21] Net present value (NPV) of the option over 20-year cash flow period from 1 July 2025 to 30 June 2045, based on discount rate of 4.05%.

[22] The overall risk level for each option after the option is implemented.

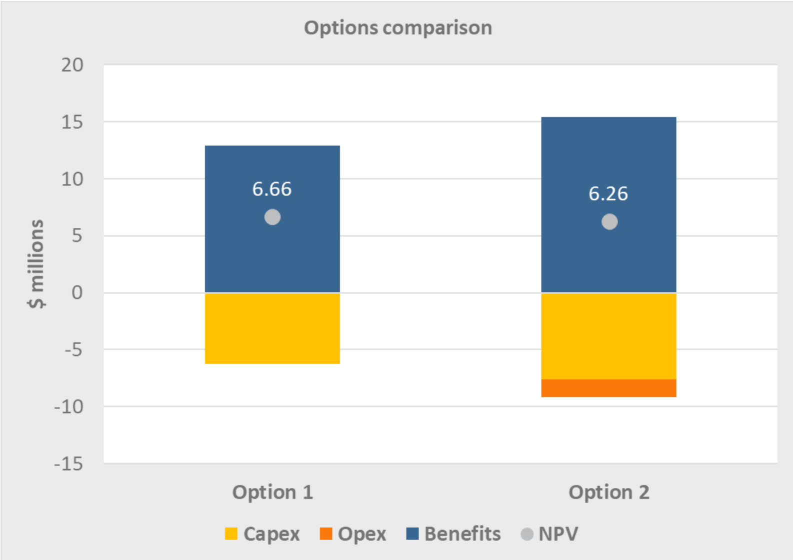
[23] Represents the present value of total capex associated with the option over the 20-year cash flow period from 1 July 2025 to 30 June 2045.

[24] Represents the present value of total opex increase associated with the option above the current level of opex, over the 20-year cash flow period from 1 July 2025 to 30 June 2045.

[25] The base case is not ranked as it is not considered to be a credible option.

Option 1 – Basic services	6.27	-	-	-	12.93	6.66	Low	1
Option 2 – Advanced services	7.61	1.54	-	-	15.41	6.26	Low	2

Figure 8 – Options comparison summary



Assumptions

- Assumed CER uptake rates are based on AEMO's Electricity Statement of Opportunity (**ESOO**) 2022 forecasts for the Step Change ISP scenario, which AEMO considers as the central case.
- The modelling assumes that we are undertaking our proposed network capacity augmentation program as set out in the associated business case (document 5.4.2).
- Other assumptions are documented in sections 8 and 9 below.

5.3.2 Recommended option

Our recommended option is option 1, a capital investment program to develop the systems and business processes to enable new tariffs, incentives and connection arrangements based on DOEs on the load side.

This option received strong stakeholder support in our stakeholder engagement program, but was not the most strongly supported option. In our Focused Conversation workshops[26], 52% of participants favoured option 2, a higher level of investment to deliver additional capabilities, having the view that the pace of change in the energy system was consistently underestimated and we could potentially miss opportunities if we under-invest in our capabilities to engage with smart demand-side technologies, VPPs and other demand aggregators. Option 2 was the option put to our People's Panel, who also endorsed the higher level of expenditure for similar reasons.

Despite the support from stakeholders, we are not recommending option 2 as our preferred option in this business case. This is because there is a degree of uncertainty on the additional benefits associated with more advanced services, given uncertainties around how the future market will evolve. Instead, we now consider that the development of more advanced demand flexibility services is best pursued via our proposed Innovation Fund, giving us greater flexibility and optionality to target expenditure to developing the specific additional capabilities and services that will deliver the most benefit in the 2025-30 RCP as these

[26] Refer section 5.5 below for more details on our stakeholder engagement program.

opportunities become clearer. Further details on the Innovation Fund are included in the associated business case (document 5.7.7.).

In summary, option 1 is recommended because:

- we consider it a prudent level of investment in this area given uncertainties associated with the additional benefits of higher levels of investment;
- our modelling indicates that it has a slightly higher forecast net positive benefit than option 2;
- the expenditure involved is lower than the cost of the option endorsed by our People's Panel; and
- we now consider the outcomes sought by stakeholders who favoured option 2 can be better achieved by pursuing more advanced services through our Innovation Fund.

Further information on the options and the cost/benefit analysis is included below in the remainder of section 5 and further information on our stakeholder engagement is included in section 5.5.

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 the 2025-30 RCP in developing the capabilities to provide DOEs on the load side or the associated advanced tariffs, incentives and connection services these enable. Our current activities in this area would be discontinued once the trials that are ongoing and planned for the remainder of the current RCP are complete.

Note that even under this option we expect a progressive improvement in demand-side flexibility, CER orchestration and price-responsiveness through the 2025-30 RCP and beyond arising from the continued transition to time-of-use tariffs as the rollout of smart meters continues[27] and from the ongoing activities of energy retailers, aggregators and VPPs. The quantified benefits included in the options analysis herein reflect only the forecast incremental benefits arising from our proposed demand flexibility programs, above this base level of improvement.

Option 0 is not a preferred option because:

- the AEMC, the AER and the community have a clear expectation that networks should seek to maximise the opportunity to engage demand flexibility to reduce the need for traditional network augmentation, improve asset utilisation and increase efficiency, and this has been a key part of our long-term network strategy for over a decade[28];
- this option has been consistently rejected by stakeholders throughout our stakeholder engagement process. In fact, as noted above, many stakeholders favoured a higher level of investment in this area, recognising the significant untapped potential of demand flexibility and expressing concerns that opportunities could be missed if we under-invest in modernising our systems to integrate with customers' future smart loads; and
- we are already starting the journey to enabling greater demand flexibility, via our Diversify tariff trial, our current engagement with commercial customers to explore flexible connection arrangements for large commercial loads such as public EV fast chargers, and our planned 'low carbon smart homes'

[27] Our modelling of load flows in the LV network for our base case and all options assumes that the AEMC's proposed accelerated meter rollout from 2025-30 with proceed as per the recommendations of the recent review of the metering framework.

[28] as described in section 7 below.

trial; these activities have received stakeholder and community interest and support on the expectation that they are part of a process of developing business-as-usual flexible demand tariffs, services and connection arrangements in future.

This option is included here only as a counterfactual to provide a baseline to compare the other options.

5.4.1.2 Costs

There is no investment in demand flexibility under this option, so costs are baselined at zero for the purpose of the options analysis.

5.4.1.3 Risks

Table 6: Risk assessment summary

Risk consequence category	Current risk level[29]	Risk cost[30]
Performance and Growth – Failure to deliver on strategic plan and growth objectives	Medium	Not quantified
Performance and Growth - Non-compliance with regulatory, legislative and/or other obligations	Medium	Not quantified
Network - Failure to transport electricity from source to load	Medium	Included in VCR
Customers - Failure to deliver on customer expectations	Medium	Not quantified
Overall risk level	Medium	

5.4.2 Option 1

5.4.2.1 Description

Option 1 is a capital investment program to develop the systems and business processes to enable new tariffs, incentives and connection arrangements based on DOEs on the load side. It includes:

- development of a short-term operational demand constraint forecasting tool using the Distributed Energy Resource Management System (**DERMS**) capability within our Advanced Distribution Management System (**ADMS**), able to produce a rolling 24-hour window of available load capacity in every LV transformer area, building on and extending the existing 'constraints engine' developed for flexible exports;
- updates to our IEEE2030.5/Common Smart Invertor Profile - Australia (**CSIP-AUS)**[31] Utility Server to enable the publication of DOEs for load as well as export capacity;
- changes to our SmartApply and SmartInstall web services and business processes to enable customers to apply to connect smart loads under flexible connection arrangements, and to validate the installation and commissioning process;
- development of new flexible load tariffs and incentives, building on our 'Diversify' tariff trial (planned to commence late 2023);
- development of new flexible load connection offers for medium- and large- sized commercial and industrial loads, including electric vehicle DC fast chargers and grid-scale batteries, along with associated communication, control and network protection solutions;
- integration of 'emergency backstop' functionality for emergency load shedding (similar to Smarter Homes generation shedding enabled today through our flexible exports system); and

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

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

[31] Common Smart Inverter Profile – Australia. The Australian profile for the IEEE2030.5 communication standard for inverters that enables flexible exports / dynamic operating envelopes

- associated work in business process re-engineering, integration with other systems (including flexible exports), technical standards and industry and stakeholder engagement.

5.4.2.2 Costs

The costs of the above activities have been estimated based on our experience developing the corresponding systems and capabilities for flexible exports, from trials through to business-as-usual. The costs of option 1 are summarised in the table below.

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	2.32	2.78	0.63	0.48	0.48	**6.68**	0.00	0.00	0.00	0.00	0.00	**6.68**
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	**2.32**	**2.78**	**0.63**	**0.48**	**0.48**	**6.68**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**6.68**

Further details on cost inputs are included in section 8 below.

5.4.2.3 Risks

Table 8: Risk assessment summary

Risk consequence category	Current risk level[32] (Option 0)	Residual risk level[33] (Option 1)	Risk cost[34]
Performance and Growth – Failure to deliver on strategic plan and growth objectives	Medium	Low	Not quantified
Performance and Growth - Non-compliance with regulatory, legislative and/or other obligations	Medium	Low	Not quantified
Network - Failure to transport electricity from source to load	Medium	Low	Included in VCR
Customers - Failure to deliver on customer expectations	Medium	Low	Not quantified
Overall risk level	Medium	Low	

5.4.2.4 Quantified benefits

The forecast quantified benefits of reduced VCR impact to customers and reduced export curtailment (refer section 5.3 above) for option 1 in the 2023-30 period and over the 20-year options evaluation period are summarised below.

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 2025-45
Capex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Opex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Customer	0.02	0.03	0.05	0.07	-0.05	**0.12**	**23.22**
TOTAL	**0.02**	**0.03**	**0.05**	**0.07**	**-0.05**	**0.12**	**23.22**

Further details on these benefit estimates are included in section 8 below.

32 The level of risk post current controls (i.e. after considering what we currently do to mitigate the risk).

33 The level of risk post future controls (i.e. after considering the impact of this work program).

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

5.4.2.5 Unquantified benefits

We also anticipate the following additional benefits that have not been quantified:

- reduced distribution and transmission losses arising from increased local self-consumption of solar;
- increased capability for flexible loads, including batteries, VPPs and other aggregated CER to participate in the wholesale and frequency support markets compared to static, non-flexible connection arrangements, due to greater access to available network capacity;
- reduced barriers to the deployment of fast EV charging infrastructure, particularly in rural locations where network capacity is limited, including lower-cost network connection options;
- emissions reduction benefits associated with improvements in hosting capacity and reduced export curtailment, contributing to the achievement of South Australia's targets for reducing greenhouse gas emissions (in line with recent changes to the National Electricity Objective[35]); and
- greater cost savings for customers through the electrification of homes and businesses.

5.4.3 Option 2

5.4.3.1 Description

Option 2 includes all of option 1, with the additional systems and near-real-time data interfaces (APIs) for VPPs, aggregators, AEMO and other market participants to communicate current and forecast network state and to extend the application of DOEs. The aim would be to facilitate:

- more effective utilisation of available network capacity to participate in wholesale and frequency support markets, e.g.:
    - pre-charging batteries prior to a period when the network is forecast to be constrained to ensure sufficient charge to respond to an anticipated market event; or
    - using portfolio or 'nodal' operating envelopes that enable the aggregator to decide how to allocate available capacity across NMIs or flexible load devices behind a higher-level network constraint; and
- more efficient operation of the wholesale market by improving AEMO's capability to forecast CER response, taking into consideration distribution network constraints – potentially integrated with the Energy Security Board's (ESB's) proposed 'Scheduled Lite' service;
- the disaggregation of operating envelopes to support the ESB's proposed 'Flexible Trading Arrangements' market model; and
- procurement of new network support services to help alleviate short-term or localised network constraints.

5.4.3.2 Costs

This option includes all the costs of option 1, plus additional costs arising from the additional scope above. The estimated have been informed by actual costs incurred in developing similar or related capabilities in our trials.

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35 See https://www.aemc.gov.au/regulation/neo, accessed September 2023

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	2.45	3.36	1.10	0.61	0.61	**8.13**	0.00	0.00	0.00	0.00	0.00	**8.13**
Opex	0.00	0.00	0.13	0.13	0.13	**0.39**	0.13	0.13	0.13	0.13	0.13	**1.04**
TOTAL COST	**2.45**	**3.36**	**1.23**	**0.74**	**0.74**	**8.52**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**9.17**

Further details on cost inputs are included in section 8 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	Medium	Low	Not quantified
Performance and Growth - Non-compliance with regulatory, legislative and/or other obligations	Medium	Low	Not quantified
Network - Failure to transport electricity from source to load	Medium	Low	Included in VCR
Customers - Failure to deliver on customer expectations	Medium	Low	Not quantified
Overall risk level	Medium	Low	

5.4.3.4 Quantified benefits

We consider that the increased level of flexible load orchestration and market participation enabled by the additional services provided under this option would lead to an incremental increase in the two benefit streams quantified above for option 1. Our estimate of these benefits under option 2 is shown below.

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 2025-45
Capex	0.00	0.00	0.00	0.00	0.00	**0.00**	**0.00**
Opex	0.00	0.00	+0.00	0.00	0.00	**0.00**	**0.00**
Customer	0.02	0.04	0.06	0.09	-0.06	**0.15**	**27.69**
TOTAL	**0.02**	**0.04**	**0.06**	**0.09**	**-0.06**	**0.15**	**27.69**

Further details on these benefit estimates are included in section 8 below.

5.4.3.5 Unquantified benefits

As well as an incremental increase in the quantified benefits above, we would also anticipate that option 2 would lead to a similar increase in the non-quantified benefits associated with option 1.

There may also be additional market efficiency benefits associated with the capability to support future market reforms such as Scheduled Lite and Flexible Trading Relationships, but, as noted in section 5.3.2 above, we have no basis on which to estimate these at this time.

5.5 Sensitivity analysis

Our benefits forecast relies on assumptions regarding the efficacy of our demand flexibility program in enabling us to reduce the customer impact of peak demand events and increase the amount of daytime load. To allow for uncertainty in these assumptions we have also modelled:

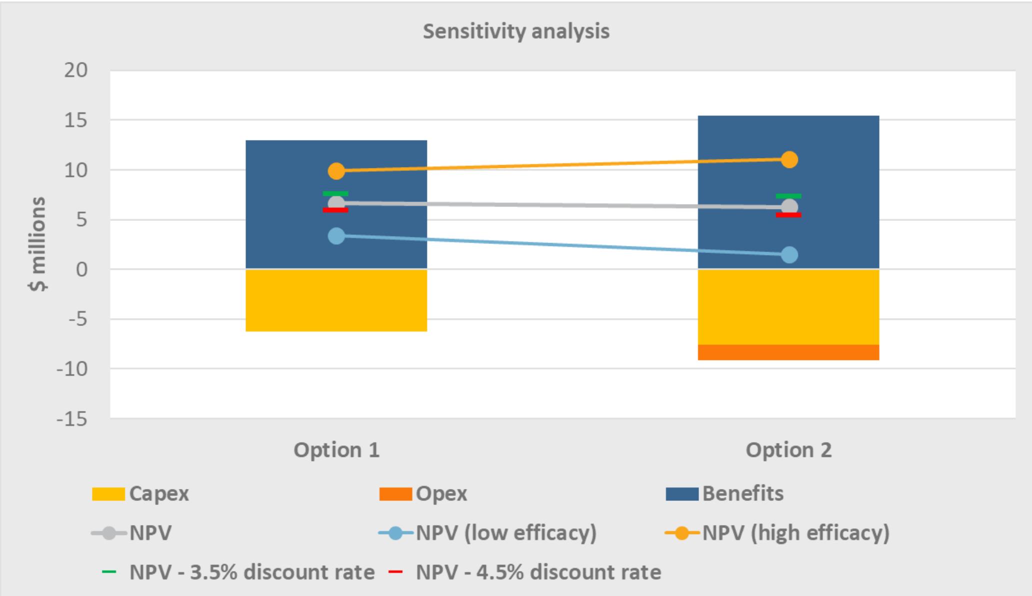
- a 'low efficacy' sensitivity case, reflecting more pessimistic assumptions regarding the impact of the program; and
- a 'high efficacy' sensitivity case, reflecting more optimistic assumptions regarding the impact of the program.

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%.

Further details of the assumptions and sensitivity cases are included in section 8.2 and Appendix B.

The outcome of this analysis is that both option 1 and option 2 have forecast positive net benefits in both upper and lower sensitivity cases, as shown in the chart below. The range of possible outcomes for option 2 is greater that our preferred option 1, reflecting greater uncertainty in the additional benefits achieved, and this option is only marginally NPV-positive with the more pessimistic benefit assumptions in our lower sensitivity case.

Figure 9 – Sensitivity analysis



Noting that only two of the anticipated benefit streams – VCR and hosting capacity benefits – have been included in the quantitative analysis, we consider that our preferred option is highly likely to deliver net positive benefits to customers.

6 How the recommended option aligns with our engagement

6.1 Alignment to customer expectations

In the last year we have seen a significant increase in the number of enquiries from commercial customers seeking to connect large loads to the network such as EV charging stations and grid-scale batteries, often combined with solar generation. These customers have expressed a strong desire for us to offer more flexible, quicker and lower-cost connection options, particularly in rural areas where constraints in network capacity present challenges for large loads and generators.

We have also undertaken a comprehensive stakeholder engagement program for our 2025-2030 Proposal involving more than 700 participants across 56 workshops and other activities around the state since the program commenced in late 2021. During this process our proposed approach to demand flexibility was canvassed along with our broader CER integration strategy as part of our 'Energy Transition' topic area.

Through this engagement process customers across all demographics indicated consistent support for prudent investment in the distribution network to facilitate greater levels of rooftop solar, enable the transition to EVs, and support the state government goal of reaching net 100% renewable electricity system by 2030, the end of our next RCP.

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 period. In these workshops we heard that customers strongly support the transition to renewable energy in South Australia, but also expect this to be managed in a way that keeps electricity reliable and affordable.

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 with stakeholders via a series of three 'Energy Transition' Focused Conversations. 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 considered and discussed the level of investment we should make in this area in 2025-30, taking into consideration indicative bill impacts. 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:

- only one out of 21 stakeholders voted for the base case ('no new investment');
- support for the other two options was quite evenly split, with option 2 ('advanced services') receiving the most votes even though it was the option with the higher estimated bill impact. Option 2 received 11 votes and option 1 ('basic services') received 9 votes, making option 2 the preferred option to carry forward to our People's Panel;

- those stakeholders who preferred option 2 did so because they had a strong expectation that we should be investing in a 'smarter' network to support the changing energy system. These stakeholders felt that the transition to EVs and continued improvements in demand-side technology between now and 2030 would create significant opportunities for us to reduce traditional network investments through demand flexibility;
- those who preferred option 1 felt that the additional capabilities in option 2 were directed more to commercial entities like retailers and VPPs than end customers, and were concerned that the additional benefits may not all flow back to customers; and
- many stakeholders did not support our initial proposal to include in option 2, expenditure to fund a South Australian trial of a flexibility services procurement platform like the Piclo Flex platform used in the UK. Two of those who supported option 2 did so on the basis that this element be removed. Stakeholders considered that the future benefits of such a trial were hard to quantify at this time, and some also felt that this kind of trial should be a national one, not something funded only by South Australian customers. Considering this feedback we removed this trial, and the associated expenditure, from the recommendation carried forward to our People's Panel. We still consider that there may be merit in such a trial in 2025-30, given the success of this platform in the UK in enabling non-network solutions, but we now propose that this be included as a potential project for our proposed Innovation Fund. Under the Innovation Fund the customer benefits of such a trial could be weighed against other innovation initiatives as the future benefits became clearer, and we could explore opportunities to reduce costs through grant funding or collaboration with other DNSPs.

Based on the above, a modified version of option 2, with the flexibility services platform trial removed, was carried forward as the recommendation to our People's Panel.

6.1.3 Our People's Panel

The final stage in our formal stakeholder engagement process was our People's Panel comprising 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 our stakeholder engagement.

The role of the People's Panel was to consider our whole proposal from a top-down perspective, reviewing the recommendations from Focused Conversations and weighing the relative importance of expenditure in each area, taking into consideration overall bill impacts. Through this process some of the recommendations made in Focused Conversations were rejected when considered in the context of the overall proposal, some were endorsed in full and others were modified. The People's Panel were strongly supportive of our overall energy transition strategy and endorsed the recommendation of our Focused Conversations in this area.

6.1.4 Feedback on our draft proposal

Since conducting the People's Panel process, we published a Draft Proposal 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 Demand Flexibility program, noting that:

- members of the People's Panel affirmed that their recommendations, including in respect of demand flexibility expenditure as set out in this business case, remain current;[36] and
- the Energy and Water Ombudsman of South Australia noted that it supports the expenditure, noting the importance of enabling customers to maximise choice in managing their devices and allow

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

operators of Virtual Power Plans and other third parties to manage their CER, and to prudently prepare to respond to ongoing market reforms. [37]

6.2 Alignment to the views of other stakeholders

6.2.1 Our national industry engagement

Industry stakeholders anticipate that the next decade will see a new generation of large, flexible loads such as community batteries, advanced data centres and fast EV chargers, as well as the progressive electrification of industrial processes. These new, smarter loads will be designed to be flexible to take maximum advantage of variable renewable energy, and this flexibility will also create opportunities to reduce network costs.

We engaged on this aspect of our proposal with our Distributed Energy Resources (**DER**) Integration Working Group (**DERIWG**), which comprises a mix of senior CER industry stakeholders from across Australia as well as senior representatives from Energy Consumers Australia, the Total Environment Centre, the Clean Energy Council, the Electric Vehicle Council, the South Australian Government and AEMO. This group is described in more detail in our CER Integration business case[38].

In workshops and online meetings, stakeholders in our DERIWG have expressed their strong support for a holistic approach to the integration of CER and new commercial loads that combines cost-reflective price signals, load flexibility, market-based solutions and the enablement of retailer, VPP and aggregator demand response and CER management schemes.

We are also active members of the national Electric Vehicle Council (**EVC**), which convenes technical working groups to facilitate national best practice in the connection of EV chargers (small and large) to the distribution network. A key concern of the EVC is that the cost to connect large highway DC fast chargers to the network can be prohibitive, particularly in rural areas where local network capacity is limited and the cost to augment the network is high.

The EVC and the charging network operators consider that this is impeding the rollout of fast charging networks and hence could also impede the adoption of EVs, particularly in rural and regional communities that may be left poorly served in terms of available charging infrastructure. They have called on distribution networks to reduce connection costs for large EV charging stations, and the EVC has specifically called upon us to allow EV charging stations that consume less than 160 MWh per annum to opt out of maximum demand tariffs. We do not favour this approach as it would be a retrograde step in terms of cost-reflective pricing that would push some of the network costs arising from commercial EV charging stations on to other small businesses.

We consider that the most efficient way to support large EV charging stations and other large commercial loads to reduce their network costs is by offering flexible connection options using DOEs that allow these loads to operate flexibly within the available capacity of the network. Using smart load balancing across charging stations, combined with a flexible network connection based on DOEs that adapts to other demand on the local network, there is tremendous potential to support fast EV charging services at lower cost than would otherwise be required. Indeed, we consider that without such flexible connection options the rollout of public fast EV charging infrastructure under current connection arrangements will likely result in over-investment in network capacity that is not well utilised.[39]

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

[38] 5.7.4 – Business case: CER integration

[39] Noting that even when all available charging stalls are occupied, a modern EV 'supercharger' charging site is rarely operating at or close to its maximum possible peak demand because even modern vehicles that can charge at very high rates (150 kW+) do so only for a short part of the charging cycle, dropping to lower rates for the latter phases of charging

We are currently engaging with charging station proponents to explore these concepts and seek opportunities to pilot these kinds of flexible connection arrangements in South Australia, to inform the development of the 'business as usual' solutions set out in this business case after 2025.

6.2.2 Alignment with industry trends and current research

In the 2015-20 period, SA Power Networks, in keeping with other networks in the NEM, conducted trials of cost-reflective network tariffs. These led to development of our 'solar sponge' time-of-use tariffs, introduced as standard in the 2020-25 period. Similarly, trials of DOEs and associated tariff and connection arrangements currently underway in South Australia and elsewhere will lay the foundations for the introduction of the business-as-usual systems proposed in this business case after 2025. Our proposed approach aligns with and will build on the approaches being explored through these trials, for example:

- Australian Renewable Energy Agency (**ARENA**) is currently funding several smart EV charging trials, including with retailers AGL[40], Origin Energy[41] and ActewAGL[42]. In its final 'Lessons Learnt' report published in May 2023[43], AGL's Electric Vehicle Orchestration Trial found that:
    - *"Customers on time-of-use tariffs are already responding strongly to the tariff signals and moving their charging to off-peak periods.*
    - *"Charging orchestration is effective in reducing charging demand to nearly zero when it is called upon, and can have a significant impact during the evening system peak.*
    - *"Customers are receptive to having their charging controlled provided they have the ability to opt out of the control and turn their charging back on at any time. In practice, the level of opt-outs is very low.";* and
- the South Australian government is currently funding nine separate EV smart changing trials in South Australia[44] and has previous funded a range of demand flexibility projects in the commercial and industrial sector under initiatives like its Renewable Technology Fund. This includes the recently commissioned IKEA microgrid project that includes a sophisticated energy management system designed to be able to provide network support services as well as reduce demand at the network connection point[45].

Our approach also aligns with the findings of a recently completed 2-year study by the University of Melbourne in partnership with Energy Networks Australia (**ENA**), the Centre for New Energy Technologies (C4NET) and the Australian Power Institute. This study examined the level of EV penetration that could be accommodated on different types of local distribution network, modelling several sample networks in NSW, Tasmania and Victoria. The study found that:

- without any financial incentives to charge outside of peak times, new peak demand constraints arose at between 20% and 40% EV penetration[46] depending on network type;
- ToU tariffs were effective at shifting demand out of peak times, increasing the number of EVs that could be accommodated by around 20% on average;
- on their own, however, time-of-use tariffs lead to 'second peak' issues at tariff price boundaries at higher levels of EV uptake; and

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40 See https://arena.gov.au/projects/agl-electric-vehicle-orchestration-trial/

41 See: https://arena.gov.au/projects/origin-energy-electric-vehicles-smart-charging-trial/

42 See: https://arena.gov.au/projects/realising-electric-vehicle-to-grid-services/

43 AGL, *AGL Electric Vehicle Orchestration Trial Final Lessons Learnt Report*, May 2023, accessed at https://arena.gov.au/assets/2023/08/20230703-AGL-Electric-Vehicle-Orchestration-Trial-Final-Report.pdf

44 See: https://www.energymining.sa.gov.au/industry/modern-energy/electric-vehicles/smart-charging-trials

45 See https://www.energymining.sa.gov.au/home/news/latest/ikeas-microgrid-switched-on

46 Where 100% means one EV per household – noting that future penetration rates will exceed 100% using this metric as most households have more than one vehicle.

- adding control signals that enable networks to manage occasional extreme peaks in demand and smooth demand across price boundaries can mitigate these issues and allow for up to 100% EV uptake with low customer impact. According to the modelling undertaken for the study, only 21%-38% of customers would experience some kind of charge management at 100% EV penetration. For these customers, the impact would be limited to a small number of occasions in the year, when either charging times would be extended, or some evening charging would be delayed until the overnight period.

Our own forthcoming 'low carbon smart homes' trial will further explore the interaction between cost-reflective price signals and load-side DOEs for households with varying degrees of home energy management capability.

6.2.3 Alignment with broader policy

We continue to engage actively on energy policy, particularly in relation to the energy transition, 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**) (in particular the DER workstream of the ESB's Post-2025 Market Review), other DNSPs through ENA, industry working groups and other relevant national bodies such as ARENA's Distributed Energy Integration Program (**DEIP**).

Our proposed approach to demand flexibility aligns with the growing support among policymakers for accelerating the transition to EVs[47] and the growing consensus that enabling demand flexibility is the key to doing this efficiently. The South Australian Government's Electric Vehicle Action Plan[48] emphasises the importance of smart EV charging, recognising that flexible management of EV charging loads has a key role to play in reducing network costs and maximising the long-term customer benefits and cost savings of the transition to EVs.

There is also growing policy support for facilitating the electrification of space heating, water heating, industrial processes and other applications that currently rely on fossil fuels (primarily gas) where electric alternatives offer compelling benefits in terms of efficiency and carbon emissions reduction[49]. The trend towards electrification has been driven in part by modelling undertaken by groups like Rewiring Australia[50] that shows that, as well as being essential to meeting our national carbon reduction targets, a rapid transition from other fuels to electricity offers opportunities for material energy cost savings for homes and businesses.

In a future where the economy is decarbonised in line with our national emissions reductions commitments, the distribution network will ultimately deliver the majority of the state's end-use energy, as illustrated in the figure below. The systems proposed in this business case establish key foundational capabilities to support this transition in a way that will minimise the future cost of the network augmentation required.

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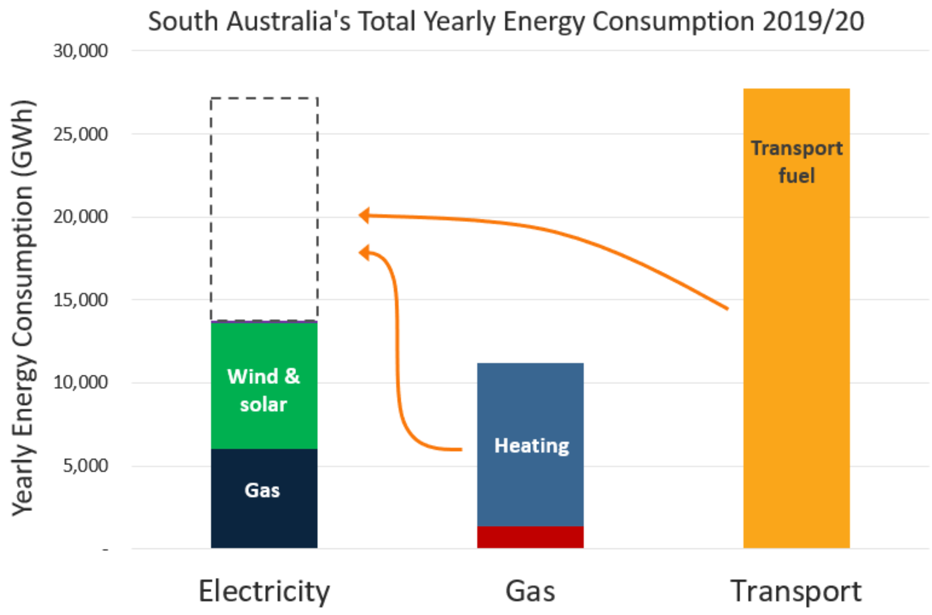
47 E.g. the *National Electric Vehicle Strategy* (see https://www.energy.gov.au/news-media/news/australias-national-electric-vehicle-strategy and the South Australian government's EV Action Plan (see https://www.energymining.sa.gov.au/industry/modern-energy/electric-vehicles)

48 See https://www.energymining.sa.gov.au/industry/modern-energy/electric-vehicles

49 See, e.g. Victoria's Gas Substitution Roadmap, available at https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap

50 See: https://www.rewiringaustralia.org/

Figure 10: Fuel sources for end-use energy consumption in South Australia, and the potential magnitude of the transition from other fuels to electricity (after taking efficiency gains into account)



Our approach is also consistent with the early findings of the policy work led by the ESB to promote a nationally consistent approach to the use of DOEs in the NEM, which has proposed IEEE2030.5 as the preferred technical standard for the communication of DOEs on the demand side, building on the successful adoption of this standard in the CSIP-AUS for flexible exports.

7 Alignment with our vision and strategy

The introduction of DOEs on the load side is one of the key next steps in an integrated long-term strategy that aims to manage the changing role of the distribution network through an efficient combination of cost-reflective price signals (tariffs), network-side and demand-side (non-network, market-based) solutions.

More than a decade ago, when we published our vision of the future in our 2013-2028 Future Operating Model[51], we wrote:

> *"by 2028… Demand Side Participation will become a key feature of customers' interaction with the network. We expect that this will facilitate two way energy flows on the network between communities and suburbs, requiring management of the low voltage network…*
>
> *"…Smart appliances are already being introduced into Australia that will enable customers to shift usage patterns, where grid pricing incentives are available. With the right incentives, customers could soon allow us to control these networked devices to provide demand reduction, enabling more efficient use of our network…*
>
> *"…The potential impact of EVs on peak demand, as well as the opportunity to tap into EV batteries to provide network support using vehicle-to-grid technology, is expected to drive the need for investment in EV integration technologies and new tariffs."*

[51] SA Power Networks, Future Operating Model 2013-2028, attachment 7.7 to our 2015-20 regulatory proposal

Engaging and incentivising demand flexibility has been a central pillar of our long-term strategy ever since, as reflected in later revisions of the Future Operating Model, our Network Strategy[52] and our DER Integration Roadmap[53].

8 Reasonableness of cost and benefit estimates

Our methodologies for estimating costs and benefits are summarised in the tables below.

8.1 Costs

Table 13: Basis of cost estimates

Cost item	Basis of estimate
Systems costs for dynamic operating envelopes on the demand side	CAPEX costs for the extension of our core CER management systems to support DOEs on the load side have been estimated based on the historical costs to develop these systems for flexible exports and Smarter Homes. These existing key components include: ▪ constraints estimator; ▪ IEEE2030.5/CSIP-AUS utility server; ▪ SmartApply and SmartInstall portals; and ▪ emergency generation shedding functions and interfaces.
Develop new tariffs, incentives and flexible connection offers and transition to BAU	These costs have been estimated based on historical costs to develop these arrangements for flexible exports, informed by our trials. They include costs for stakeholder engagement and service co-design, internal business process re-engineering, and transition through pilot to BAU.
Develop communication solutions for medium and large loads	These costs have been estimated based on historical costs to develop low-cost communication solutions for medium and large embedded generators to reduce customer connection costs compared to traditional SCADA integration.
Option 2 additional API and service development costs	Option 2 includes additional APIs for market participants to provide near real-time data feeds for network state, as well as facilities to provide 'portfolio' or aggregated DOEs. The cost to develop the technical systems and interfaces, as well as new business processes, to support these more advanced services and data interfaces have been estimated based on the costs incurred and experience gained in our ARENA-funded Advanced VPP Grid Integration trial[54] and related work.
Operating costs – option 1	We have not included any OPEX step change in our proposal for our recommended option, option 1. While there are some costs in software licensing, data processing, telecommunications and hosting, the dominant factor affecting OPEX growth in these areas in 2025-30 will be scaling these systems to support forecast growth in flexible exports. For option 1 we do not expect the incremental system operating costs associated with flexible loads to be sufficiently material to warrant an additional OPEX step change. Similarly, while there will be some incremental staff requirements arising from the operation and management of the new systems, they are not expected to be material given the synergies with flexible exports, and we will seek to offset any additional costs with efficiency gains through the business process re-engineering phase of the initiative.

52 5.7.1 Network Strategy

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

54 See https://arena.gov.au/projects/advanced-vpp-grid-integration/

Cost item	Basis of estimate
Operating costs – option 2	Option 2 includes new outward-facing services for market participants and VPP aggregators. As there are no analogous services today (outside trials) we forecast an addition 0.5 FTE in our New Energy Services / Retailer Relations team from 2027/28 onwards to support these new services, including on-boarding new data access seekers and ongoing support.
Top-down challenge	After individual cost items had been estimated as above, the overall program cost was subject to internal top-down review to consider the staging of work over time and potential program-level synergies and efficiency gains in common activities such as change management and project management. This activity resulted in a small reduction to the original bottom-up cost estimates.

8.2 Benefits

Table 14: Basis of benefit estimates

Benefit item	Basis of estimate
Value of avoided export curtailment (CECV)	The value of avoided export curtailment is calculated using a 'with and without' analysis using our LV Planning Engine. We modelled the long-term impact of additional shifting of flexible loads to the daytime arising from new demand flexibility services and incentives. Increasing daytime loads and encouraging more optimal behaviour of batteries has the effect of reducing export curtailment over time. To quantify the associated benefit we use a modified version of the AER's CECV that also incorporates a component for the value of avoided generation capacity investment. It is important to note that our modelling incorporates an assumed increase in CER orchestration, price responsiveness and demand flexibility over time even in the base case. This arises primarily from the continued transition to time-of-use tariffs as the rollout of smart meters continues, but also from the ongoing activities of energy retailers, aggregators and VPPs. This forecast underlying increase in orchestration of CER is built into AEMO's Integrated System Plan (**ISP**) forecasts of state-wide maximum and minimum demand, on which our models are based, and we factor these effects into the load profiles and other assumptions used in our LV Planning Engine model. Our modelling also assumes, in the base case, that tariff transition will proceed at a rate consistent with the Australian Energy Market Commission's (**AEMC's**) proposed accelerated smart meter rollout from 2025-2030. The quantified benefits included in the options analysis herein reflect only the forecast incremental benefits arising from our proposed demand flexibility programs, above this base level of improvement. Note also that this analysis is based on our forecast of the level of export curtailment before making the investments in additional export capacity proposed in our CER integration business case. This ensures that there is no double-counting of benefits: the CECV value attributed to the demand flexibility program in this business case is not included in the CECV values associated with the network capacity upgrade options considered in the CER integration business case. Rather, all the options for network investment considered in the CER integration business case start from a baseline that assumes that our 2025-30 demand flexibility program will go ahead, and the underlying level of CER orchestration will increase accordingly. This also means that the CECV benefit attributed to our demand flexibility program is independent of the level of investment in additional export capacity (i.e. independent of which investment option of those considered in the CER integration business case is chosen). Details of the modelling and our use of the CECV are included in our CER Integration business case[55] and the associated methodology document.
Value of Customer Reliability (VCR)	VCR benefits are estimated based on the reduced customer impact of capacity exceedances during peak demand events in 2025-30. Our goal is to reduce the risk of unplanned outages during extreme demand events by pro-actively curtailing load for customers who have opted into flexible connection arrangements to protect the network.

55 5.7.4 - CER Integration - Business Case

Benefit item	Basis of estimate
	While flexible customers still suffer a loss when their load is curtailed, we assume that this is much lower than the regular VCR associated with an unscheduled outage, since the load in question has been nominated by the customer as flexible. The load at risk in 2025-30, and hence the maximum VCR, is derived from our capacity augex forecasts, as described in the associated business case[56], and is the difference between the VCR outcome under our proposed capacity augex program (option 1 in that business case), which is based on a hybrid probabilistic / deterministic planning approach, and the VCR outcome under a purely deterministic planning approach (option 2 in that business case). Our proposed program has a lower cost than option 2 but has around $12 million more residual VCR risk[57]. As load DOEs are a new capability we do not have historical data on which to base our estimates of the efficacy of this approach in reducing VCR impacts so we have sought to take a conservative approach to estimating this benefit. Our central assumption is that by 2030 the amount of flexible load will be sufficient to reduce at most 30% of the residual VCR at risk arising from peak demand growth in the 2025-30 period, assuming our proposed capacity augex program proceeds as planned. Where we are able to manage peaks in demand using active curtailment with DOEs, we assume that the unserved energy due to this kind of curtailment has a VCR that is 10% of the regular VCR, reflecting the significant reduction in customer impact of active curtailment of flexible loads under opt-in flexible load management arrangements compared to the impact of an unplanned outage. To account for uncertainty in these estimates we have tested figures above and below these as part of our sensitivity analysis, as summarised in Appendix B.

9 Reasonableness of input assumptions

Our key input assumptions are summarised below.

Table 15: Basis of key input assumptions

Input assumption	Basis
CER uptake forecasts - **Solar** - **Battery** - **EV** **Peak demand growth forecasts** **Load profiles (customer underlying demand, hot water, batteries, EV charging, etc)**	Growth forecasts are derived from AEMO's August 2022 ESOO forecasts for South Australia based on the ISP Step Change scenario as the central case. Load profiles are based on an analysis of sample smart meter data, load profiles from customer batteries including VPP orchestration, and other data sources. Input data has been prepared using independent modelling and advice from external consultants Blunomy (formerly Enea) and EVenergi. Further details are included in the CER integration business case[58].
Network capacity (peak demand)	Peak demand capacity and future N and N-1 risks, which are key inputs to estimating future VCR benefits from demand flexibility, have been estimated using our core network capacity planning methodology as described in our capacity augmentation business case[59].
Network capacity (export)	Network hosing capacity (export capacity), which is a key input to estimating future CECV benefits from demand flexibility, has been estimated using our LV Planning Engine using the methodology described in our CER integration business case.

56 5.4.2 - Augex Capacity - Business case

57 Based on a 20-year NPV, $June 2022.

58 5.7.4 - CER Integration - Business Case

59 5.4.2 - Augex Capacity - Business case

A. Appendix A - Risk assessment

ID	Risk scenario	Consequence description	Consequence category	Current risk (Option 0) Consequence	Current risk (Option 0) Likelihood	Current risk (Option 0) Risk Level	Residual risk (Option 1) Consequence	Residual risk (Option 1) Likelihood	Residual risk (Option 1) Risk Level	Residual risk (Option 2) Consequence	Residual risk (Option 2) Likelihood	Residual risk (Option 2) Risk Level
1	Failure of flexible demand system leads to asset overloads in either forward or reverse direction.	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	4	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	3	1	Low
		Localised outages due to asset overloads affecting multiple customers.	**Network** - Failure to transport electricity from source to load	3	1	Low	3	1	Low	3	1	Low
2	Peak demand event leads to involuntary load shedding due to lack of flexible capacity. Either there is no flexible capacity able to be reduced to mitigate a forecast extreme	Greater reliance on customer involuntary load-shedding to manage extreme peaks in demand.	**Customers** - Failure to deliver on customer expectations	3	3	Medium	2	3	Low	2	2	Low
			Performance and Growth – Failure to deliver on strategic plan and growth objectives	3	3	Medium	2	3	Low	2	2	Low

ID	Risk scenario	Consequence description	Consequence category	Current risk (Option 0) Consequence	Likelihood	Risk Level	Residual risk (Option 1) Consequence	Likelihood	Risk Level	Residual risk (Option 2) Consequence	Likelihood	Risk Level
	peak event (option 0) or we are unable to achieve the intended level of voluntary load reduction through flexibility due to lower than expected uptake or lower than expected efficacy.		**Network** - Failure to transport electricity from source to load	3	3	Medium	2	3	Low	2	2	Low
3	Peak demand growth is higher than expected, leading to more frequent and severe demand curtailment for flexible customers (options 1 and 2), or more frequent involuntary load shedding (option 0)	Flexible load customers experience a worse level of service than they expect, leading to customer dissatisfaction and potential financial losses to customers. To the extent that this undermines customer confidence in the approach it could set back our long-term strategy to maximise use of demand flexibility and lead to higher investments in traditional network capacity augmentation in future.	**Customers** - Failure to deliver on customer expectations	3	3	Medium	2	3	Low	2	3	Low
			Performance and Growth - Non-compliance with regulatory, legislative and/or other obligations	3	3	Medium	2	3	Low	2	3	Low
			Overall Risk Level[60]			Medium			Low			Low

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

B. Appendix B – sensitivity case inputs

Our NPV analysis considers how sensitive the NPV of our proposed work program is to variations in key input assumptions. The sensitivity analysis includes low-efficacy and high-efficacy sensitivity cases for CECV and VCR benefits, as well as testing sensitivity to different assumed discount rates. These are shown in the table below.

Table 16: Sensitivity cases

	Option 1			Option 2		
Input	**Central**	**Low**	**High**	**Central**	**Low**	**High**
Percentage of VCR at risk that can be targeted by demand flexibility in 2025	2%	0%	2%	2%	0%	2%
Percentage of VCR at risk that can be targeted by demand flexibility from 2030 onwards	30%	20%	40%	35%	25%	50%
VCR for flexible loads curtailed under opt-in flexible schemes as % age of standard VCR for involuntary loss of supply	10%	20%	5%	10%	20%	5%
Daytime load shifting efficacy: daytime load increase from flexible loads compared to central case (option 1)	100%	80%	120%	120%	85%	150%
Discount rate for NPV analysis	4.05%	3.50%	4.50%	4.05%	3.50%	4.50%