Innovation Fund Business case addendum

2025-30 Regulatory Proposal

Supporting document 5.13.4

December 2024

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
API	Application Programming Interface
ARENA	Australian Renewable Energy Agency
BAU	Business as Usual
BOM	Bureau of Meteorology
Capex	Capital expenditure
CAF	Community Advisory Forum
CECV	Customer Export Curtailment Value
CER	Community Energy Resources
CERIAG	CER Integration Advisory Group
CESS	Capital Expenditure Sharing Scheme
CFS	Country Fire Service
CSIP-AUS	Common Smart Inverter Protocol - Australia
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System
DERAPITWG	DER Application Programming Interface Technical Working Group
DOE	Dynamic Operating Envelope
DMIAM	Demand Management Innovation Allowance Mechanism
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefits Sharing Scheme
ESO	Electricity System Operator
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
GHG	Greenhouse Gasses
HV	High Voltage
IAG	Innovation Advisory Group
ICT	Information and Communication Technology
IEA	International Energy Agency
ISC	Interoperability Steering Committee
ISP	Integrated System Plan
LV	Low voltage
NEO	National Electricity Objective
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
MED	Major Event Day
MFS	Metropolitan Fire Service

OEM	Original Equipment Manufacturer
OPEX	Operating expenditure
RAG	Reset Advisory Group
RCP	Regulatory Control Period
RIT-D	Regulatory Investment Test for Distribution
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
TOU	Time of Use
VER	Value of Emissions Reduction
VPP	Virtual Power Plant
VVWO	Volt-Var-Watt Optimisation

About this document

Purpose

This document is addendum to the original business case in our Regulatory Proposal (submitted to the Australian Energy Regulator (**AER**) 31 January 2024) *'5.7.7 Business case: Innovation Fund Jan 2024*, which should still be read for background information, including with respect to the key themes for the Innovation Fund and how these were arrived at, the overall identified needs for each theme, our earlier customer engagement and how this informed our Regulatory Proposal.

This document now responds to the AER Draft Decision having not approved our proposed expenditure forecast for the Innovation Fund, and addresses each of the concerns raised by the AER in arriving at this Decision.

Expenditure category

- Other non-network capital expenditure **(capex)**
- Other non-network operating expenditure **(opex)** – category specific forecast

Related documents

This document should be read together with the following related documents.

Ref	Title
[1]	5.13.4.1 – Innovation Fund – Project Estimates
[2]	5.7.4 – CER Integration – Business Case
[3]	5.7.5 – Demand Flexibility – Business Case
[4]	5.7.7 – Innovation Fund – Business Case

Executive summary

This business case addendum recommends an expenditure forecast of **$20 million** ($June 2025) ($16 million in capex, and $4 million in opex) for the 2025-30 Regulatory Control Period (**RCP**), to establish an Innovation Fund that will be governed together with our customer groups, and which will fund trial projects that have the potential to drive transformative change and long-term customer benefits.

The need to both undertake innovation and to establish an Innovation Fund arises from several factors:

- the unprecedented changes occurring via the energy transition, which have the potential to drive material costs on the distribution network if not managed effectively – including via increased electrification of homes, businesses and transport driving resurgent demand, as well as continued demand for use of the network to transport energy exported from renewable distributed generation;
- the network will, in coming years, face ever increasing risks arising from climate change, driving increases in the severity and frequency of major weather events and increasing the divide between service reliability experienced by customers in urban versus regional areas;
- conversely, technological change is presenting new opportunities for how the distribution network can be managed and built in the future, minimising the extent of new investments that need to be made in coming years; and
- while there are some existing funding sources for innovation projects, a separate Innovation Fund is still required, on the basis that:
  - sources such as the Australian Renewable Energy Agency (**ARENA**) require matched funding contributions and may only be complementary to certain qualifying projects – where applicable, we intend to continue to leverage and exhaust opportunities for ARENA funding; and
  - the AER's Demand Management Innovation Allowance Mechanism (**DMIAM**) has both a very low funding cap, and a scope that is too narrow to cover the breadth of challenges that the Innovation Fund seeks to respond to.

The AER Draft Decision did not allow forecast expenditure for the Innovation Fund, providing instead a 'placeholder' value of $0. While the AER recognised that ex-ante expenditure for an Innovation Fund has a place within the regulatory framework, further information was sought before the AER could approve a forecast, including: an assessment of each proposed project against its new assessment criteria, further information on estimated costs and consumer benefits, and a firm list of proposed projects.

We do not accept the Draft Decision but recognise that our original business case did not provide sufficient information. This addendum addresses each of the AER's concerns, and recommends $20 million as the prudent and efficient expenditure level required to pursue innovation in the 2025-30 RCP, on the following basis:

- **customer prioritised firm project list** - this case now includes a list of innovation projects that:
  - have costs that in total reconcile to the forecast expenditure for the Innovation Fund; and
  - cover 9 high priority project areas that were prioritised by our customers via the subsequent and specific engagement that we undertook – this includes eight projects focused on the 'Enabling a flexible future[1]' innovation category, and one project focused on the 'community resilience' innovation category;
- **compliance with assessment criteria** - the proposed projects are shown in this addendum to comply with the AER's new assessment criteria, by: involving transformative innovation, having identified

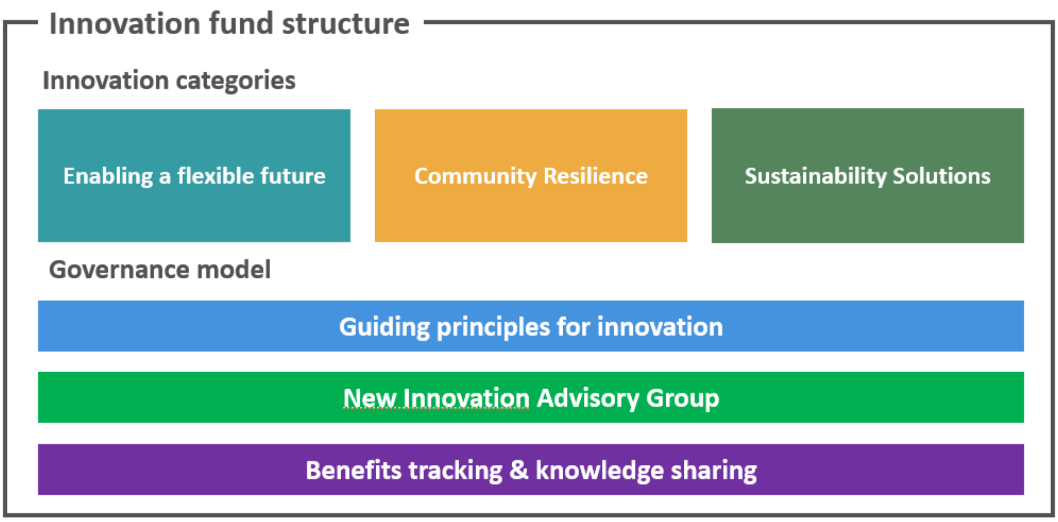
[1] This theme has been relabelled from "Enabling and Leveraging the Future Market" to more clearly reflect the proposed projects

needs pursuant to the expenditure objectives in the National Electricity Rules (**NER**), not duplicating other funding sources, having appropriate scaling for trials and clear pathways to broader implementation;

- **cost estimation** - the costs of the proposed projects are now further detailed and itemised; and
- **consumer benefits** – we have outlined the range and sources of material customer benefits expected to arise from successful innovation, which we expect will cover:
    - improving utilisation of the distribution network;
    - minimising the need for future network augmentation;
    - driving down wholesale market energy costs;
    - improving the security of the energy system;
    - increasing the Value of Emissions Reduction; and
    - improving the climate resilience of the network, and therefore supply reliability and safety to customers;
- **customer-led governance model** - a detailed governance model set out, whereby:
    - a new 'Innovation Advisory Group' (**IAG**) comprising a range of customer and stakeholder representatives, will empower customers to shape the identification and any reprioritisation of innovation projects, applying a set of 'assessment principles for innovation' that will be used during the RCP to ensure that projects are indeed truly innovative and are capable of delivering the types of customer benefits that our IAG expects;
    - learnings derived via the Innovation Fund will be shared publicly; and
    - safeguards will ensure that any unspent funds will be returned to customers.

The overall structure of our proposed Innovation Fund is displayed in *Figure 1*. The Innovation Fund would still have regard to the potential for projects across the three Innovation Categories described in our original business case as these provide a continual focus for our work with the IAG. However, as described above, the firm list of projects proposed in this addendum now only cover two of these categories (enabling a 'enabling a flexible future', and 'community resilience').

Figure 1 Innovation fund structure



1 Background

1.1 Our original proposal

The original business case in our Regulatory Proposal[2] recommended forecast expenditure of $20 million ($June 2025) in the 2025-30 RCP, with an 80/20 percent split between capex and opex (i.e. $16 million in capex, $4 million in opex) to establish a new Innovation Fund to pursue initiatives considered capable of driving long-term customer benefits, and structured around the pursuit of projects under three innovation themes / categories:

1. **Enabling a Flexible Future** - improve network utilisation by piloting innovations in network planning and operations in a Consumer Energy Resources (**CER**) heavy future, incentivising flexible use of existing network assets through new customer-facing demand flexibility products and integrating this flexibility into the planning of the wider energy system;
2. **Community Resilience** - innovative solutions to managing the reliability of our network in regional and remote communities, as well as during extreme weather events, working with community groups and emergency services to enhance community resilience; and
3. **Sustainability Solutions** – accelerate our decarbonisation by implementing innovative approaches to managing our field operations, including electrifying our heavy vehicle fleet and exploring solutions to best integrate heavy Electric Vehicles **(EV)** into our outage management process.

The focus themes for the Innovation Fund and its inclusion in our Regulatory Proposal were recommended by our customers through several stages of our engagement program.[3]

Further, our original business case also provided:

- indicative detail on the potential projects under each theme but did not seek to provide a definitive list of projects, reflecting our desire (and that of our customer groups at the time) to maintain a degree of flexibility as to the innovation we would pursue during the RCP in response to fast changing circumstances. In subsequent AER information requests, further project-specific detail was provided; and
- a governance framework, building on the governance models used by other networks to ensure projects and outcomes were aligned to customers' needs and delivered clear customer benefits – this included an agreement to establish a sub-committee of our Community Advisory Board (now the Community Advisory Forum, **CAF**) with whom we would work collaboratively to develop innovation fund project selection principles and provide program oversight.[4]

[2] SA Power Networks, *Business Case: Innovation Fund [5.7.7],* January 2024

[3] SA Power Networks, Attachment 5: Capital Expenditure, January 2024, p.77.

[4] SA Power Networks, *Business Case: Innovation Fund [5.7.7],* January 2024 Section 4.4

1.2 How we have revised our approach

The Draft Decision to disallow our proposed expenditure and substitute it with a 'placeholder' value of $0, reflects the fact that the AER accepted the premise, role and need for having an explicit ex-ante expenditure allowance to pursue innovation projects, particularly given the pace of the energy transition.

The AER's substitute placeholder value was applied, pending the AER receiving further information as to:

- the list of projects we propose;
- how they comply with their new assessment criteria (set out in breakout box 1);[5]
- the quantified costs;
- expected consumer benefits; and
- how knowledge would be shared and reported.[6]

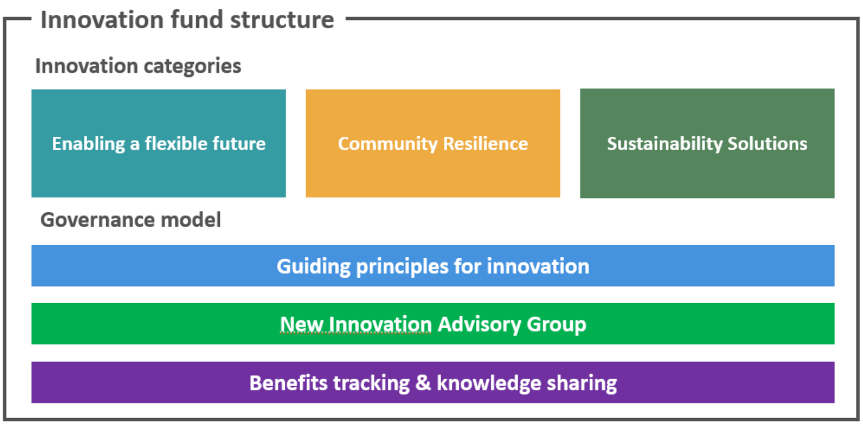
We disagree with the Draft Decision allowing $0 expenditure, and our revised forecast remains at our originally proposed $20 million ($16 million capex, $4 million opex).

In response to the Draft Decision, this addendum has addressed each of the specific concerns identified by the AER, including accounting for the AER's views as to the potential non-compliance with its assessment criteria of some of the projects we had initially been considering. We have enhanced our overall approach to the Innovation Fund to comprise the elements displayed in Figure 2

Box 1: AER assessment criteria 1

1. **Innovative** – projects must be transformative;
2. **Expenditure objectives** – the justification for the proposed projects must be linked to the expenditure objectives in the NER;
3. **Alternative funding** – explain how existing incentive schemes, allowances, government grants have been genuinely exhausted;
4. **Project scaling and implementation pathway** – projects must be prudent from a scale perspective for a trial / pilot phase, including success factors / criteria applied to trials / pilots to assess whether it proceeds to the business-as-usual phase; and
5. **Stakeholder support** – there is support for the innovation expenditure

Figure 2: High level innovation fund structure



The key changes in our approach are that:

1. we have provided more detail on our justifications;
2. while we initially had an extended list of potential projects, we have prioritised this list and proposed the highest priority projects, as supported by our customer groups through further engagement; and

5 The assessment criteria were set out after the lodgement of our Regulatory Proposal, and first introduced as part of the AER's distribution determinations for the NSW, ACT, Tas DNSPs.

6 AER, *Draft Decision SA Power Networks Electricity Distribution Determination 2025 to 2030: Attachment 5 Capital Expenditure*, September 2024, p.38.

3. fully developed our customer-led governance framework for the Innovation Fund.

Table 1 summarises all of the changes and further information that we have provided to address each specific concern raised in the AER's Draft Decision and the further input from our customers through the subsequent engagement that we have done since receiving the Draft decision. These points are detailed throughout this addendum.

Table 1: SA Power Networks response to AER and stakeholder feedback on the Innovation Fund proposal

AER feedback	How we responded
Application of AER assessment criteria	
▪ Initial proposal was too conceptual and further information is needed on the scope and efficiency of the intended projects. ▪ Projects must be justified against the AER assessment criteria. This includes, among other things, demonstrating why the projects are transformative rather than core improvement and efficiency that should be part of normal business operations.	Each project has been justified against and evidenced to comply with the AER's criteria (see *Sections 6* and *7*) Applying the AER's criteria and having regard to the AER's assessment in the Draft Decision,[7] we removed projects from our initially extended project list, as these could not be justified (including resilience batteries and heavy electric vehicle projects). We engaged with our stakeholder and customer representatives to include within our Innovation Fund Principles a specific principle to ensure future project proposals align to AER feedback for transformative innovation (see *Section 4.1*), requiring that projects are: *"**Truly innovative** and adapted or aligned to SA context"*
Propose a firm project list	
1. Reconciling to the proposed expenditure forecast. 2. Demonstrating the detailed cost build-up and input assumptions. 3. Detailing the expected type of benefits and efficiencies and how these will be measured. 4. Detailing project timelines.	A firm project list is proposed (see *Sections 3, 6* and *7* and in the attached spreadsheet).[8] In summary: 1. The cost build-up in the attached spreadsheet reconciles to the expenditure forecast of $16m capex and $4m opex ($20M total expenditure). 2. All projects have been re-assessed and re-estimated to a prudent pilot scale, with a larger number of small-scale pilots now proposed. 3. A supporting spreadsheet contains individual worksheets for each project, with detailed cost build up and the input assumptions. 4. Expected benefits are described for each project (summary *in Sections 6* and *7*). 5. The start time of each project will be subject to ongoing prioritisation by our customers, via our proposed IAG. Project timelines are provided indicating the project duration and sequence of activities (see *Sections 6* and *7*).
Knowledge sharing	
▪ Explain how knowledge from innovation projects will be shared with industry, consumers and regulators.	▪ Knowledge will be shared as per our refined approach to the Fund's governance (see *Section 4.4*), which was developed with and prioratised by our customers via subsequent engagement.

[7] AER Draft Decision Attachment 5 Capital Expenditure, p.38.

[8] 5.7.8 – Innovation Fund – Project Estimates

▪ Demonstrate how any shared lessons have been considered and used to inform the proposed projects and what the incremental benefit of the project is.	▪ We have detailed how industry knowledge has been leveraged in developing each individual project we propose (see *Sections 6* and *7*).
The role of the DNSP	
▪ Explain if SA Power Networks is the appropriate party to undertake the proposed innovation compared to a contestable market, and any ring-fencing concerns.	We have explained why our proposed projects should be undertaken by SA Power Networks as a DNSP (see sections 6 and 7).
	Explaining how projects fit into a strategic continuum
	While not required, we explain how our proposed projects are not the product of random selection but rather fit within a broader and well-considered continuum in terms of how we can best respond to the profound energy transition in South Australia. In particular, how innovation in flexibility can assist in enabling the transition with minimal need for network upgrades, increasing utilisation and putting downward pressure on distribution prices for all customers.
Stakeholder views	**How we responded**
Flexibility to respond to change during the period	
There is a need for a degree of flexibility in the project list during the RCP, to ensure that customers by way of the IAG, can be empowered to assist SA Power Networks in responding to the changing external environment and stakeholder and customer needs. This is particularly noting the difficulty of anticipating all required innovation for a 5-year period.	We engaged with our stakeholder and customer representatives to develop and obtain their endorsement for a clear governance model, which includes a set of Innovation Fund Principles that will be applied during the RCP, to assist with any further prioritisation required (see *Section 4*).
Potential for clear customer benefits	
There is a need to ensure that each project, including any new projects during the RCP, has the potential to deliver clear benefits for *all* customers, not just CER customers, and that these benefits are tracked and reported on to all relevant stakeholders.	We engaged with our stakeholder and customer representatives to include within our Innovation Fund Principles, a specific principle ensuring that projects are only funded where the potential for customer benefits are clearly present: *"**Customer-centric,** focused on delivering benefits and outcomes for <u>all</u> customers"* Further, our proposed knowledge sharing framework (see *Section 4.4*) outlines how knowledge as well as customer benefits will be shared with customers, industry and regulators.

2 The context to our investment needs

2.1 Innovation themes / categories address distinct identified needs

Consistent with our original business case, which was informed by customer feedback though engagement on our original proposal, we retained three overarching themes of innovation that aim to serve as a focus for the innovation work that we will undertake in collaboration with customers via our IAG during the RCP. However, for this business case addendum, in preparing a prioritised list of projects with our customers and having regard to the AER's assessment in its Draft Decision, we have not retained projects under each innovation theme.

Each overarching theme has a distinct identified need for innovative approaches as a means of responding to emerging challenges and opportunities in order minimise traditional network investment and otherwise minimise future costs to consumers, as follows.

Innovation category 1: Enabling a flexible future

This category identifies the need to respond to the rapid and sustained growth in CER uptake and technology advancements in South Australia, which necessitate significant innovation in network planning and operation to continue to meet customer expectations and our regulatory obligations. In addition to the NER expenditure objectives, NER Section 4.3.4 mandates each distribution network service provider (**DNSP**) to cooperate with the Australian Energy Market Operator (**AEMO**) in maintaining power system security and managing emergency frequency control schemes.

The pace of change is expected to accelerate in the 2025-30 RCP, with continued CER growth, increased customer participation in Virtual Power Plant (**VPP**) and other aggregation schemes, and the emergence of smart, connected loads like EV chargers. This rapid evolution of customer-side technology will further drive the need for innovation to ensure it can be integrated into the distribution network in a way that minimises whole-of-system costs and makes the best use of existing network assets.

Eight of the nine Innovation Fund projects proposed in this addendum are under this Innovation category, as prioritised by our customer groups, including our CAF and Reset Advisory Group (**RAG**).

Innovation category 2: Community resilience

This category identifies the need to respond to the fact that South Australia's climate is changing, leading to forecasts of increased frequency and severity of extreme weather events and fire seasons, as per the State of the Climate 2024 report[9]. These changes will pose risks to the reliability of electricity supply to customers, with severe weather causing significant network damage and outages, as seen in 2022. These outages affect community resilience, disrupting essential services like communication, emergency response, supermarkets, and transport. Communities and service providers often lack information about their exposure to these outages and their vulnerabilities.

To enhance community resilience, SA Power Networks needs to collaborate with communities and service providers to understand and mitigate these vulnerabilities. Recent technological advancements, like energy storage systems, offer potential solutions. However, using these solutions solely for network support may be inefficient. Joint funding arrangements and revenue sharing with third parties could improve efficiency and customer value.

One of the nine Innovation Fund projects proposed in this addendum is under this Innovation Category, as prioritised by our customer groups, including our CAF and RAG.

[9] State of the Climate 2024: Bureau of Meteorology (bom.gov.au)

Innovation category 3: Sustainability solutions

This category identifies the need to respond to the imperative of reducing emissions as now enshrined as a directive within the National Electricity Objective (**NEO**) in the National Electricity Law (**NEL**) and in the NER. We have a target of net-zero for Scope 1 and Scope 2 greenhouse gas (**GHG**) emissions by 2035. This also aligns with the views of our customers and stakeholders that we should respond to their concerns about climate change and their desire to see us adopt greener operations, particularly by reducing emissions. Initial steps include transitioning our light vehicle fleet to EVs. However, challenges exist, including the lack of EV options for heavy vehicles and the need to integrate EV charging into our scheduling systems. Our original business case proposed that the Innovation Fund would help explore cost-effective solutions for these issues, enabling the full electrification of our fleet.

However, through our engagement with customers subsequent to the Draft Decision and having regard to the AER's assessment we have decided in this addendum to no longer propose any projects under this Innovation Category. As outlined above, this Innovation Category will remain only as an overall focus lens for our engagement with customers during the RCP.

2.2 Proposed projects address distinct identified needs within each category

While the Innovation Categories / themes set the broad investment imperatives driving our consideration of potential Innovation Fund projects, each of our proposed projects has a distinct identified need within the context of the expenditure objectives in the NER and NEL. These needs are briefly summarised *Table 2*, and detailed on a project-by-project basis in *Sections 6* and *7*.

Table 2 Summary of identified needs addressed for each proposed project

Theme	Priority	Project	Identified need
Flexibility	1	CER market operations interface pilot	Improve the accuracy of information used by AEMO in operational forecasting, namely constraints on the distribution network, to increase the accuracy of demand forecasting and the setting of wholesale market prices. Relevant NER clauses: *6.5.7(3)(iv), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	2	Advanced Network Planning for a Flexible Future trial	Increase network utilisation and optimise whole-of-system planning across both the distribution and transmission networks by developing new end-to-end planning tools to co-optimise investments in CER flexibility with network augmentation and integrate these tools into AEMO's system planning function to realise a lowest whole-of-system cost view. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1) & 6.5.7(c)(1)(a)*
Flexibility	3	Local Flexibility Marketplace pilot	To increase network utilisation and avoid future augmentation by improving the visibility of network constraints and the accessibility of providing a solution to those constraints, creating a unified marketplace for response to constraints from the low-voltage through to transmission level. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*

Resilience	4	Emergency Services data sharing	Enhance operational collaboration between SA Power Networks and state emergency services to improve restoration times during emergency scenarios. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	5	Self-Serve Connections Platform Pilot	Facilitate timelier and more accurate load and CER connection assessments for customers and stakeholders, of network capacity and constraints including voltage limits. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	6	Co-optimising network real and reactive power trial	Increase network utilisation and reduce wholesale pricing by harnessing greater reactive power response from CER as an alternative to active power curtailment. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	7	Distributed emergency underfrequency response pilot	Reduce reliance on feeder load-shedding by procuring emergency under-frequency response from CER, improving system security and customer reliability. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(3)(iv), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	8	Shared market flexibility pilot	Reduce the costs to operate a VPP and drive greater VPP participation for the purposes of lowering wholesale prices, by utilising shared communications pathways between a DNSP and a VPP operator. Relevant NER clauses: *6.5.7(3)(iii), 6.5.7(1), 6.5.7(c)(1)(a) & 6.5.7e(5A)*
Flexibility	9	Integrating dynamic operating envelopes (**DOEs**) and system services pilot	Increase system security by enabling greater provision of frequency controlled ancillary services (**FCAS**) and other essential system services from distributed CER, mitigating the risk imposed by exiting thermal generation in the National Electricity Market (**NEM**) and lowering the costs of maintaining a stable power system. Relevant NER clauses: *6.5.7(3)(iv), 6.5.7(c)(1)(a) & 6.5.7e(5A)*

2.3 The innovation fund responds to a gap in the regulatory framework

Our original business case and information provided in response to AER information requests have justified why there is a need for explicit and ex-ante funding of expenditure on innovation within the regulatory framework. It is our interpretation that this is not a matter in question with the AER, noting that the Draft Decision accepted this need and stated that its decision to allow $0 expenditure was only to serve as a 'placeholder' until future information was provided in support of our proposed programs.

For the avoidance of doubt, we reiterate our reasons why the Innovation Fund will not be duplicative with any other external funding sources or AER incentive schemes, as follows:

- **the Demand Management Innovation Allowance Mechanism (DMIAM) is unable to fund the innovation required** – the DMIAM has immaterial funds and is limited in scope, focussing only on demand management projects. Its funds are capped at $200,000 plus 0.075% of a DNSPs annual revenue requirement, which will be fully utilised in the 2015-20 and 2020-25 RCPs. It is insufficient to fund required innovation in the 2025-30 RCP given the pace of the energy transition;
- **existing expenditure incentive schemes cannot fund innovation programs –** existing schemes by way of the Capital Expenditure Sharing Scheme (**CESS**) and Efficiency Benefit Sharing Scheme (**EBSS**), while incentivising cost efficiencies cannot fund innovation programs aiming to drive improvements in service performance or customer value. They also increase risk for DNSPs incurring expenditure on innovation that could lead to a scheme penalty, despite the benefits of innovation potentially accruing over a longer-term period (i.e. across multiple RCPs) and ultimately serving to reduce future allowances;
- **service performance incentive schemes cannot fund innovation programs** - the Service Target Performance Incentive Scheme (**STPIS**) is only suited to implementing tried and proven solutions that can deliver immediate service outcomes pertaining to reliability performance (and more specifically, reliability excluding Major Event Days, **MEDs**). In contrast the Innovation Fund intends to explore innovation that can improve outcomes that are broader than just reliability and the benefits of which accrue over multiple RCPs;
- **the Innovation Fund will not duplicate external funding sources** - we have committed (See *Section 5.1.4* of our *5.7.7 Innovation Fund Business Case*, and expanded in *Section 4*) in the Innovation Fund's design that we will firstly actively seek opportunities to leverage other potential funding sources (e.g. ARENA or the Race for 2030 CRC, or government grants) should they be available in relation to the proposed priority initiatives. However, these external funding sources such as ARENA often do not provide sole funding for an initiative, and require that the party receiving funds also contributes a significant or equal share – that is, ARENA would only contribute to an initiative selected as part of SA Power Networks' Innovation Fund rather than provide sole funding.[10] Therefore, the Innovation Fund has the added benefit of unlocking additional external funding sources for innovation; and
- **'Sandboxing' is not a funding mechanism –** this process is not intended to be a funding mechanism but rather a means of facilitating a no-regulatory action exploration of initiatives that may cross over lines of regulated and unregulated services or the roles of varying market participants.

[10] Refer to the ARENA Advanced Renewables Program guideline, which indicates in section 3.10(a) the amounts of cash and in-kind contributions expected from parties requesting funding, typically requiring a minimum of a 1-to-1 contribution. ARENA, *Advanced Renewables Program Guidelines*, July 2020, p.8. Accessible on: [https://www.arena.gov.au].

3 Proposed expenditure and project prioritisation

The Draft Decision identified a concern that our original business case did not contain a firm plan on the specific projects being proposed, indication of customer support, and total project costs reconciling to our proposed expenditure. We acknowledge that these concerns arose because our original plan reflected a desire for flexibility that was greater than the AER's intent. That is, we had identified an extended list of potential innovation projects that were credible to consider in the 2025-30 RCP, with total costs adding to more than our proposed $20 million expenditure forecast, with the intent to select projects from this list during the RCP in conjunction with our customers.

To address the AER's concerns, we engaged further over multiple specific sessions with our customer groups (the CAF and RAG), and now propose the following in our Revised Proposal a firm list of innovation projects which have been prioritised in sequence, as developed with our customer groups, as summarised in Table 3 Proposed prioritised list of projects for the Innovation Fund.

Table 3 Proposed prioritised list of projects for the Innovation Fund

Priority		Project	Capex ($2025)	Opex ($2025)	In original proposal?
Flexibility	1	CER market operations interface pilot	$2.62M	$0.35M	✓[11]
Flexibility	2	Advanced Network Planning for a Flexible Future trial	$1.09M	$0.37M	
Flexibility	3	Local Flexibility Marketplace pilot	$3.52M	$1.55M	✓[12]
Resilience	4	Emergency Services data sharing	$0.51M	$0.09M	✓
Flexibility	5	Self-Serve Connections Platform Pilot	$1.81M	$0.39M	✓[13]
Flexibility	6	Co-optimising network real and reactive power trial	$2.83M	$0.32M	
Flexibility	7	Distributed emergency underfrequency response pilot	$1.07M	$0.69M	✓[14]
Flexibility	8	Shared market flexibility pilot	$1.26M	$0.13M	
Flexibility	9	Integrating DOEs and system services pilot	$1.13M	$0.10M	
	TOTAL EXPENDITURE		**$16M**	**$4M**	

[11] Project was originally included as part of *Enabling VPPs and supporting post-2025 market reforms* in IR002

[12] Project renamed from *Flexibility Services Procurement Platform* in IR002

[13] Project renamed from *Instant Network Connections Assessment Tool* in IR002

[14] Project renamed from *Advanced System Security Functions* in IR002

This firm project list:

- includes some projects from our original proposal, but has removed some and included new projects that we identified based on:
  - our latest assessment of the NEM landscape;
  - the AER's analysis that some of our initial projects would not comply with its Assessment Criteria;
  - our assessment that the projects in our now revised firm list all comply with the AER's assessment criteria; and
  - this firm, prioritised list now being the product of our engagement with customers subsequent to the Draft Decision.
- now focuses mainly on Innovation Category / Theme 1 (Enabling a Flexible Future) with 8 of the 9 projects being within this category, and 1 within the Innovation Category 2 (Community Resilience);
- contains total costs that reconcile to the expenditure forecast that we are proposing in capex and opex; and
- the costs of all projects have been further substantiated including with respect to input assumptions, and these costs reflect appropriately sized scoping for innovation trials – for projects originally proposed, our re-scoping has resulted in cost reductions ranging from 25-65%.

While our Revised Proposal now includes a firm project list, we are also conscious of the desire of our customer groups, reflected via our continued engagement, that some flexibility is needed during the RCP to appropriately empower our customer groups to help prioritise and reprioritise as circumstances change during the RCP. Therefore, a further revision that we have made is to develop together with, and endorsement of, our customer groups, a set of Innovation Fund Principles, that we will apply during the RCP to aid discussions on any potential reprioritisation required. These Principles will:

- ensure that projects do meet stakeholder needs by delivering on the customer benefits they expect us to pursue, that projects are not duplicative and account for past learnings;
- ensure our customer groups are empowered to influence our innovation decisions in the RCP; and
- that the AER has additional confidence that should new market / network imperatives arise, that innovation projects will only proceed if they are in customers interests, within the context of the NER and NEL.
- Proposed projects fit within a strategic long-term view of changes, costs and value to customers

The projects comprising our firm list, have not resulted from random selection but rather a well-considered continuum of strategic thought. That is, and as explained below, we have considered:

- the long-term changes occurring in the energy sector;
- the potential effects of these changes on the effectiveness and costs of the services that we provide our customers; and
- the options by which we can most effectively manage our network and interact with customers and the market to minimise costs and maximise value to customers over the long term.

3.1 Enabling a Flexible Future

Context to the energy transition in South Australia

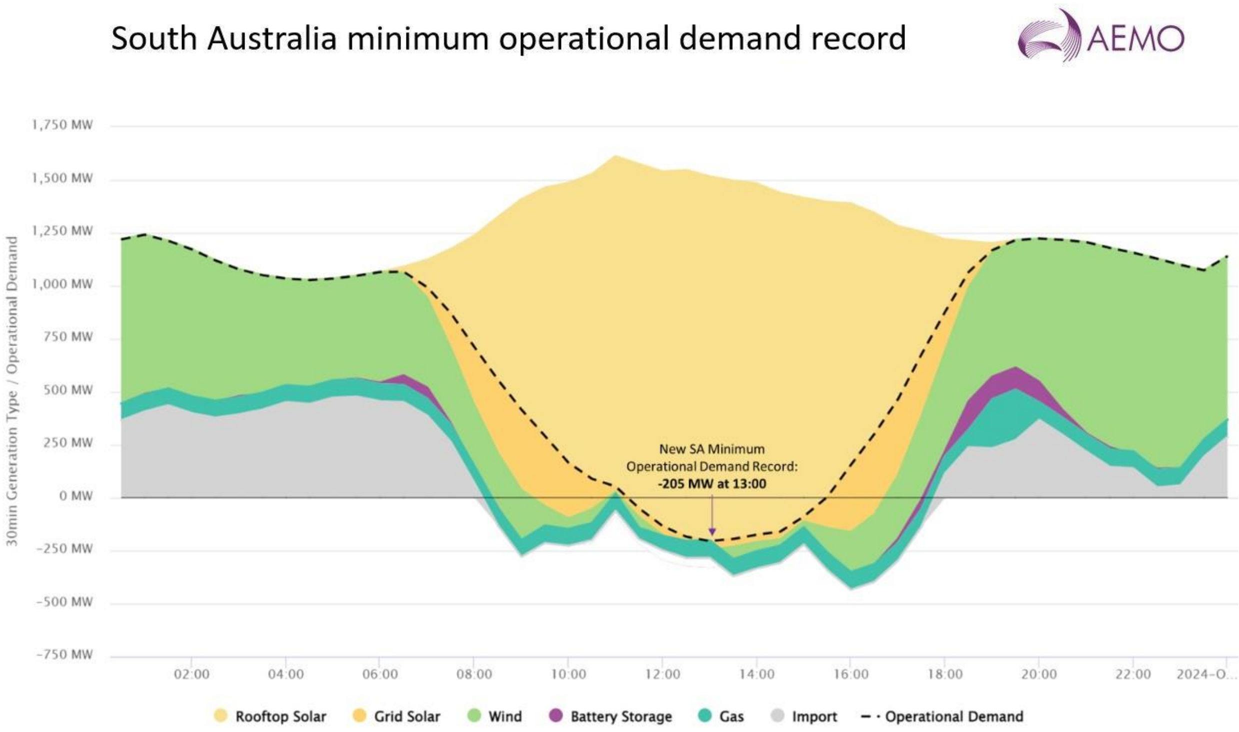
While the energy transition toward variable renewable energy is occurring across the NEM, South Australia is leading the NEM and the world in this transition. These changes will pose key challenges to manage on customers behalf, as follows:

- the level of renewables, in particular rooftop solar connected and continuing to connect to the distribution network poses challenges for both the operation of the distribution network and for AEMO in balancing demand and maintaining power system security in the NEM. This is noting that:
  - South Australia is leading the world in the transition to variable renewable energy, with more than 75% of the State's energy needs met by wind and solar alone in 2023. Consumers are leading much of the transition, with more than 360,000 homes, or 44% of residential customers, having installed rooftop solar as of October 2024. Installed rooftop solar capacity currently stands at 2.65GW, with solar regularly supplying the entire state demand (including transmission-connected loads) and exporting the excess to Victoria;
  - a report by the International Energy Agency (**IEA**) ranked South Australia as one of three grids globally (including Denmark and Ireland) as 'Phase 5' out of 6 on the journey to an exclusively variable renewable grid, requiring advanced technology and approaches to maintain reliability;[15] and
  - South Australia also leads the nation in the uptake of residential storage systems, with almost 60,000 installed across homes and business in South Australia. Although these batteries help to soak up some of the surplus energy from rooftop solar, the volume of new solar capacity continues to significantly outpace new battery capacity year-on-year, resulting in the aforementioned issues continuing to manifest for the foreseeable future.
- changes toward increasing electrification will, without intervention, in coming years potentially double peak demand on the distribution network and require significant and widespread investment in the network to meet this demand. This is noting that:
  - to maximise the use of their significant investment in solar and batteries, we anticipate many households will electrify their homes, businesses, and transport in the coming decade;
  - modelling by Rewiring Australia indicates that customers with all electric homes and vehicles could save thousands of dollars on their overall electricity bills[16]. If customers electrify as forecast, the South Australian distribution network is estimated to supply 60% of the state's energy needs, up from 20% today. Without intervention, this could double peak demand on the network and require significant and widespread investment in the distribution network to meet this demand.

[15] https://www.iea.org/reports/integrating-solar-and-wind

[16] https://www.rewiringaustralia.org/report/castles-and-cars-discussion-paper

Figure 3 SA Operational demand and generation mix, 19th October 2024



Our considered potential strategic responses

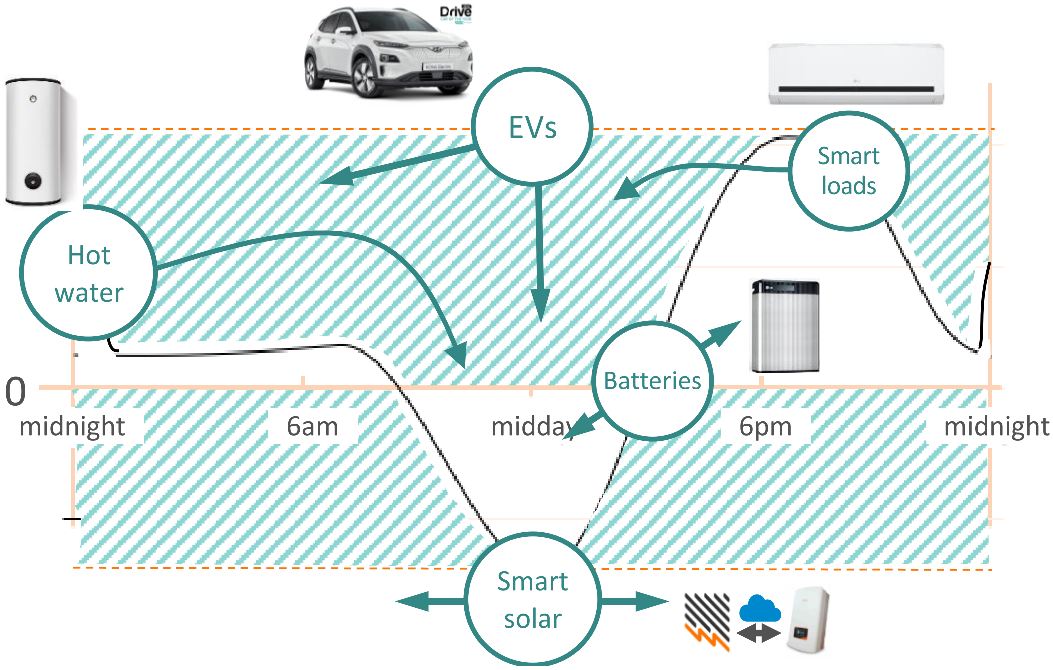
With distributed renewable energy driving unprecedented minimum demand, and the electrification of households, business and transport potentially driving significant increases in peak demand, there would broadly be three strategic choices to meet and manage this demand for service.

- **Augmenting the network** to support new peak and minimum demand, which would:
  - place upward pressure on distribution prices; and
  - drive worsening utilisation of the distribution network.
- **Restrict customer choice** in installing new technologies, which would:
  - require low static export limits and expensive traditional load connections;
  - not be customer friendly; and
  - constrain / halt the energy transition and the benefits it could deliver for all customers.
- **Leverage CER and customer flexibility** and embrace CER in network planning and operations, which would:
  - involve offers of flexible connections for load and generation to incentivise network usage outside of peak periods, thereby improving network utilisation;
  - support development of an ecosystem that enable customers to readily subscribe to such services;
  - procure services from CER to resolve network constraints; and
  - optimally augment the network when economically efficient to do so.

While some degree of network capacity augmentation will always need consideration, a key focus of the projects in this Innovation fund is in pursuing means of unlocking new opportunities to drive and make use of greater flexibility (strategic option 3). Leveraging flexibility on the customer side, will help minimise future costs and maximise value of the energy transition for customers over the long term, and is consistent with the intent reflected in the NER expenditure objectives of seeking to not just meet demand for service but efficiently manage this demand.

Unlocking flexibility to minimise network costs has been a key focus of our business particularly in the current 2020-25 RCP. Recognising the significant network capacity outside of rare network peak periods to enable many of the new applications customers have been investing in, we have been encouraging and incentivising demand and generation outside of peak network periods, otherwise known as demand flexibility, through a combination of network tariff signals on the load side (e.g. Time of Use (**TOU**) tariffs, and solar sponges), as well as implementing flexible exports in order to manage exports on the network within the hosting capacity of the distribution network. This has served to significantly minimise the need for network augmentation and driven greater utilisation of our network, putting downward pressure on network costs for all customers.

Figure 4 Illustration of the demand flexibility concept

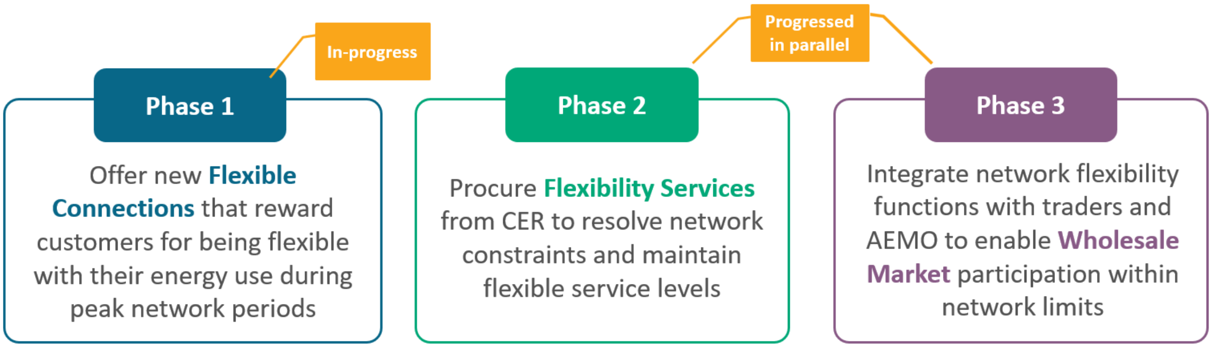


Looking forward, we see even greater potential to unlock flexibility to minimise network costs by further embracing CER in our network planning and operations and drive further flexibility including with respect to load (demand) and not only export. However, we need to evolve our capabilities, functions and services to enable this flexibility, as has been occurring over several years already. We see our new additional objective in this new environment as being to:

Actively manage CER flows on the distribution network to maximise customer and community benefit of CER, better utilise existing network capacity minimising the need for network upgrades, and maintain power system security.

To achieve this objective, we envisage the need to deliver new services and capabilities across three phases:

Figure 5 Phases for new capability delivery to support a flexible future



Each of these phases delivers the following new functions and services:

- **Phase 1: Flexible connections:**

  Backstop mechanisms: mandatory requirements on load and or generation customers to maintain system security under minimum or maximum demand conditions.

  Flexible network connections: new opt-in connection offers that reward customers for being flexible via responding to DOEs. These offers significantly increases utilisation of the network reducing the need for network upgrades to support higher amounts of CER.

- **Phase 2: Flexibility Services:**

  Flexibility service procurement: direct procurement of CER response via publication of network constraints within a flexibility marketplace platform. Procured response will avoid the need for network upgrades, increasing network utilisation.

- **Phase 3: Wholesale market integration:**

  Shared market flexibility: leverage DNSPs investment in CER digital communications and infrastructure to enable customers to optionally participate VPPs via their chosen retailer or aggregator. This provides a fast low-cost way for CER to integrate into the wholesale market, increasing competition and driving down wholesale electricity costs for all customers.

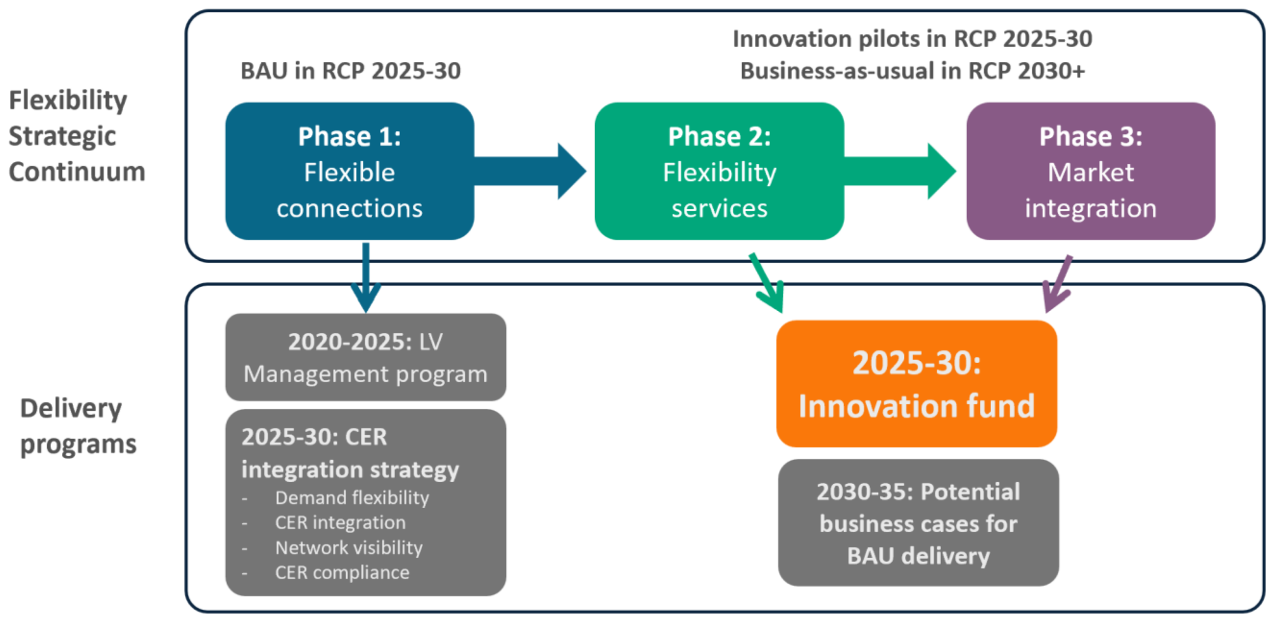
These new functions and services will depend on several enabling capabilities as shown in Figure 6.

Figure 6 New capabilities required to support a flexible future, mapped to the delivery phases

The projects that we proposed in this Innovation Fund, under the Innovation Category of Enabling a Flexible Future, reflect a carefully considered and staged continuum of evolving capabilities to continue to unlock flexibility to minimise network costs:

- Phase 1 has been our current focus:
  - in the 2020-25 RCP, and using funding approved for low voltage (**LV**) management in the AER Determination for the 2020-25 RCP, we have been building the foundational capabilities to support new flexible connection offers, and this has culminated in: the successful trial and launch of the world's first Flexible Export offer for residential solar customers; the launch of the Energy Masters pilot Flexible Import connections for residential electrified customers; and the commencement of a program of works to deliver flexible import and export connections for commercial and industrial customers; and
  - in the 2025-30 RCP, we will be undertaking further work to complete this development in flexible capabilities and extending it to the load side via the funding approved by the AER with respect to our 'demand flexibility business case', with the aim to have all offers as business-as-usual by 2030.
- Phases 2 and 3 are largely untested and require research, pilots and trials and are therefore the focus of our Innovation Fund:
  - the technology, solutions and approaches in these phases are largely untested and required research, pilots and trials to prove concepts and associated customer benefits; and
  - therefore, our innovation fund contains a suite of pilots that will work to prove these functions, leveraging knowledge from other CER integration pilots across the country, such that if successful, they can then be transitioned into BAU solutions to be applied more broadly in the 2030-35 RCP –Figure 7 below shows our Innovation Fund projects on 'Enabling a Flexible Future' fit within this long term strategic continuum and how they relate to our other CER integration initiatives.

Figure 7 Mapping of enabling flexibility strategic continuum to past regulatory business cases



3.2 Community resilience

The context

The climate in South Australia has been and will continue to change posing increasing challenges to the reliability and safety for customers, and the resilience of communities particularly in our regional areas:

- the State of the Climate 2020 report by the Australian Bureau of Meteorology (**BOM**) and the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) found that the effects of climate change are now apparent in Australia. The report forecasts that the changing climate will lead to more frequent extreme weather events in South Australia, and longer and more intense fire seasons;[17]
- these extreme weather events have implications for the electricity service we provide our customers, particularly in relation to the reliability of supply. For example, in late 2022 a series of intense storm fronts damaged the network and caused widespread outages impacting 163,000 customers – the largest event since the system-wide blackout in 2016; and
- community resilience to these extreme weather events is also impacted when network supplies are interrupted as the effectiveness of key essential services such as communications infrastructure, emergency response providers, supermarkets, and transport rely on energy. Communities and providers of essential services also have limited information regarding the extent of their exposure to network outages and what vulnerabilities they face, and the extent to which they should act to efficiently address these vulnerabilities.

Our considered strategic response

While climate change is likely to continue to increase the likelihood and impact of severe weather events and create challenges for network reliability, advances in technology present an opportunity to improve community resilience at lower cost or in locations where traditional network solutions are not economically viable. Some examples we are exploring include:

- the potential use of energy storage systems to improve community resilience to extreme weather events by providing backup power to critical community resources. However, if used in isolation for the purpose of network support, such solutions may be inefficient, but initiatives to test joint funding arrangements with third parties and various revenue sharing arrangements could change this, and drive customer value. We have been successful in procuring funding from the ARENA Community Battery Funding Round 1[18], which includes two community resilience batteries to provide backup power to key community infrastructure during extended outages, which will inform the future use of storage for this purpose;
- the more immediate priority is to explore the use of modern data sharing technology to provide network and outage information to the community, and essential services and critical infrastructure providers during severe weather events. The sharing of this information enables the co-ordinated dispatch of emergency services, improving safety outcomes and reducing the risks to critical infrastructure and the community; and
- therefore, our innovation fund contains a pilot in which we propose to partner with essential services providers to develop and trial an Application Programming Interface (**API**) to share this data, testing the technology solution and measuring the community benefits. If successful, this will form the basis of a business-as-usual implementation.

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[17] CSIRO and Australian Bureau of Meteorology, State of the Climate 2020, November 2020

[18] https://arena.gov.au/news/arena-funds-national-community-battery-roll-out/

3.3 The long-term value proposition for customers

Innovation pilots to prove the technology and approach to addressing the challenges facing energy system and the services we provide customers are expected to drive significant long-term benefits to all of our customers. This will be achieved through a combination of minimising costs to serve, increased value to customers and the broader NEM, as well as enhanced system security.

The justifications provided in this addendum for each Innovation Fund project outline the specific types of consumer benefits that we expect each project will drive (see *Sections 6* and *7*), and the range of sources of customer benefits are summarised in Figure 8 below.

Figure 8 Customer benefits targeted by innovation fund projects

4 The governance framework

4.1 Safeguards will ensure funds are directed to promoting customers' interests

Our Revised Proposal, as reflected in this addendum, includes a firm list of projects which were prioritised via engagement with our customer representative groups. However, we are also conscious of the need to empower these groups to work collaboratively with us during the RCP, as we for example, observe the lessons learned from implementing each project, and respond to any changing circumstances. Our customers considered that this was critical given the pace of change in the sector and the difficulty of anticipating all required innovation over a 5-year RCP.

To enable this to occur, while ensuring that our actions during the RCP do serve to promote customers' interests, we have developed a governance framework for the Innovation fund with three core elements:

- **Innovation Advisory Group (IAG) -** designed to ensure customer and industry oversight, input and visibility is provided for the prioritisation, selection and delivery of innovation fund projects;
- **guiding principles for innovation -** to guide the assessment and ongoing monitoring of project delivery by the IAG and SA Power Networks to ensure that projects being pursued are prudent, fit-for-purpose and focused on the customer outcomes and benefits that the IAG see as a priority. These principles, set out in Table 4, have been developed in collaboration with our CAF and RAG and are aligned to the AER's assessment criteria; and
- **knowledge sharing, reporting and benefits tracking -** to ensure the lessons and successes of our innovation activities can be shared widely with our peers and the broader industry, thereby expanding the impact of our innovation investments, reducing the potential for double up across network service providers and advancing the energy industry in Australia.

Table 4 – Guiding principles for the Innovation Fund, as agreed by stakeholders in the CAF and RAG

Guiding principles for the Innovation Fund	
Principle	**Rationale**
1. **Customer-centric**, focused on delivering benefits and outcomes for *all* customers	*All projects must seek to provide customer benefit*
2. **Truly innovative** and adapted or aligned to SA context	*Projects must not be for BAU activities or generally expected efficiency improvements*
3. **Efficient delivery of projects within the regulatory allowance granted for the fund**, with unspent funds returned	*Funding should be returned to customers if not spent on innovation projects*
4. **Projects cannot duplicate funding by the DMIAM** and will seek to leverage external sources where appropriate	*External funding should be leveraged where appropriate to increase return on investment and add greater value for customers*
5. **Projects are appropriately sized** for trial/pilot and include success criteria and pathways for business as usual (**BAU**)	*Projects support new truly innovative activities and include pathways for BAU*
6. **Collaboration and knowledge sharing** to maximise customer benefits and impact of investment	*Investment should be maximised by sharing innovation and concepts with industry and other NSPs for replication and industry improvement*

4.2 Our customer and stakeholder groups will have oversight of fund allocation

A core aspect of our governance framework is the establishment of a new CAF sub-committee, the IAG, as endorsed by our CAF and RAG. The IAG will collaborate with us to ensure customer input and oversight of innovation investment and projects throughout the 2025-30 RCP.

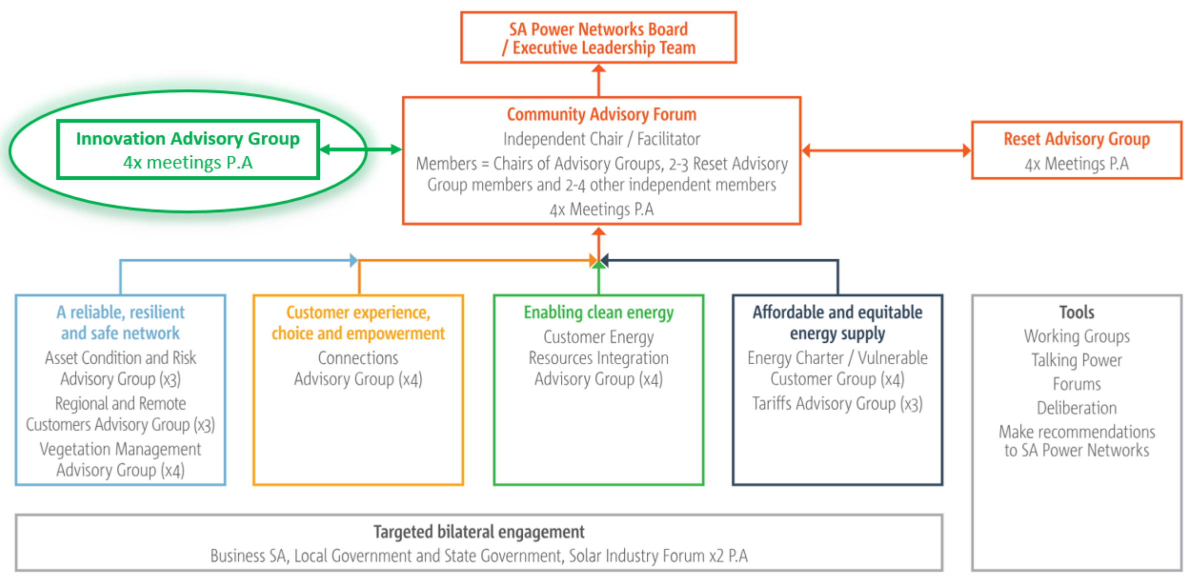
Recognising the value of customer and industry input, we also now propose to utilise the new IAG to support us in our broader innovation activities across the business beyond the Innovation Fund projects. The IAG has been formed in collaboration with, and has the endorsement of our CAF and RAG and will:

- convene a minimum of four times annually, with additional meetings as required - sessions will be documented, with minutes recorded and endorsed. Early discussions will focus on streamlining and finalising governance, including the IAG's Terms of Reference.
- utilise SA Power Networks' business cases, reports, decision-making documents, and other relevant materials that the IAG requires to exercise its duties;
- membership of the IAG will include community and industry representatives from our CAF and CER Industry Advisory Group (**CERIAG**), drawn from nominations and agreed with our CAF Chair; and
- the IAG's purpose and functions will be as set out in *Table 5* below.

Table 5 - Purpose of the proposed Innovation Advisory Group

INNOVATION ADVISORY GROUP	
Purpose To provide customer and industry input and visibility into the prioritisation, selection and delivery of Innovation Fund projects	
Innovation Fund projects Provides customer and industry input into: • **project prioritisation** • **project design and delivery** • **new project suggestions** • **future innovation opportunities** • **monitoring delivery and providing feedback**	**SAPN's innovation activities** Provides customer and industry visibility into key relevant innovation projects at SAPN to: • enable **suggestion of customer and industry problem statements or ideas** for consideration by the framework; and • ensure **adequate visibility of the broader innovation activities** to inform the innovation fund

Figure 9 - Proposed Innovation Advisory Group in the context of SA Power Networks' engagement framework



4.3 Any unspent funds will be returned to customers

Our approach has consistently sought to align to the desire of our customers to ensure that SA Power Networks does not benefit in the situation where the allowed capex and opex for the Innovation Fund is unspent, to ensure that customers are not disadvantaged. Therefore, our proposed approach is to implement a 'use it or lose it' approach to the fund as follows:

- the forecast opex ($4M) has been:
  - treated as a 'category specific forecast', as intended by the Draft Decision – this ensures that the spend funds do not get built into the opex base year that is used to set the forecast opex for the 2030-35 RCP; and
  - excluded from operation of the EBSS to prevent any benefit being derived from underspends
  - unused funding of the opex component of the Innovation Fund will be returned to customers in the 2030-35 period;
- the forecast capex ($16M) has been:
  - identified as a specific line in our accounts that we will maintain, such that we can transparently report this to customers and the AER in subsequent determinations;
  - excluded from the operation the CESS to prevent any benefit from being derived from underspends; and
  - the financing benefit associated with any unused portion of the capex component of the innovation fund will be returned to customers in the 2030-35 RCP. The financing benefit can be calculated using the AER's CESS model methodology.

4.4 Learnings from innovation will be shared

The Draft Decision sought further information on how the learnings from funded projects would be reported and shared. We support this need, recognising the value of knowledge sharing in minimising potential duplication of innovation between network service providers, and to maximise benefits to customers. As a national leader in network innovation, we have a long history of sharing the outcomes and learnings of innovation projects via various mechanisms. For example, our 'Flexible Exports' initiative is now being progressively adopted by DNSPs across the NEM following our ongoing knowledge sharing and promotion of its successes and implementation approach.

Therefore, to ensure appropriate knowledge sharing via the Innovation Fund, we propose several approaches, described as follows and summarised in Table 6 below:

- we will share knowledge via various mechanisms – this includes consistent quarterly reporting to the IAG, annual AER reporting and a variety of public knowledge implementation and sharing reports; and
- the establishment of project-specific and Innovation Fund benefits tracking to enable objective and consistent articulation of benefits derived from Innovation Fund investment to support our knowledge sharing and reporting activities; and
- we will continue our very active participation in the variety of industry forums, government working groups and advocacy activities we undertake as a leading innovator in the industry.

These proposed mechanisms, set out in the table below, are designed to:

- align to AER requirements and SA Power Networks' governance;
- ensure IAG oversight, participation and influence on innovation fund activities; and
- maximise knowledge sharing and investment impact.

Table 6 list of proposed knowledge sharing and reporting

Knowledge sharing, reporting and benefits tracking			
Knowledge sharing and/or reporting	**Reporting**	**Knowledge sharing**	**AER requirement?**
• Quarterly IAG reporting	✓		✓
• Annual reporting to AER on expenditure and delivery	✓		✓
• Public post implementation project reports	✓	✓	
• Knowledge sharing reports for DNSPs and industry		✓	✓
• Industry forums, government working groups and advocacy activities		✓	
• Project-specific and Fund benefits tracking	*Supports reporting and knowledge sharing objectives*		

4.5 We regularly engage with other market participants to avoid duplication

The knowledge sharing and reporting we propose will, in combination, minimise the risk of duplication by other Australian NSPs, and ensure that we can learn from other parties in our ongoing innovation activities. Further, we also commit to continuing our very active participation in the wide variety of industry forums, government working groups and advocacy discussions in the industry, which include, for example:

- the Energy Networks Australia's Future Network Forum, a regular forum for DNSP delegates designed to share knowledge about topics and projects related to the energy transition;
- national CER Roadmap working groups;
- ARENA's Distributed Energy Integration Program (**DEIP**) working groups, including the Flexible Imports working group, Interoperability Steering Committee (**ISC**) and Distributed Energy Resources (**DER**) Application Programming Interface Technical Working Group (**DERAPITWG**);
- participation in Australian Energy Market Commission (**AEMC**) rule change and market review consultations;
- participation in the AEMO CER forum and CER functional requirements work program;
- presentations at a variety of local and international conferences;
- regular informal knowledge exchanges with Australian and international electricity networks;
- participation in relevant Energy Charter working groups; and
- facilitation of the SA Power Networks CER Integration Advisory Group **(CERIAG),** including national representatives from market bodies, retailers, technology providers, aggregators and consumer representatives.

5 Our further engagement with customers and stakeholders

The original business case was included in our Regulatory Proposal as it aligned to the preferences of our customers as communicated through the engagement leading up to our Proposal.

To address the concerns identified in the Draft Decision, we subsequently conducted further detailed engagement specifically in relation to the Innovation Fund via our CAF and RAG. The engagement focused on seeking their input to and endorsement of the proposed firm list of innovation projects and the governance framework, as set out in this addendum. This was as follows:

1. we engaged with the CAF and RAG to outline the AER's Draft Decision and the concerns that it wanted to see addressed – we discussed various options by which to refine our Revised Proposal;
2. taking on board their feedback, we then undertook a 'deep dive' workshop with CAF and RAG members to seek feedback on the proposed list of projects and collaboratively finalise the design and seek endorsement on the proposed refined governance arrangements for the Innovation Fund. As part of this, we took on board their input to the specific wording of our Assessment Principles (as described earlier in *Section 4.1*); and
3. in agreement with the CAF and RAG, we issued a survey to seek the CAF and RAG's final prioritisation of the proposed list of initial projects for inclusion in this revised business case.

In addition to the feedback on the proposed list of projects, CAF and RAG feedback can be summarised in the following core themes that influenced the final governance arrangements, which are set out in *Table 7* below, along with how we have addressed this feedback in our proposed governance arrangements.

Table 7 Consumer and stakeholder feedback

CAF and RAG feedback	Response
The need for flexibility in the project list during the period to respond to the changing external environment and stakeholder and customer needs	Worked with our stakeholder and customer representatives to agree on a clear governance model and set of Innovation Fund principles that will guide project prioritisation within the 2025-30 RCP.
The need to ensure each project has the potential to deliver clear benefits for all customers, and that these benefits are tracked and reported on to all relevant stakeholders	Worked with our stakeholder and customer representatives to include an Innovation Fund principle which will ensure projects are only funded where the potential for customer benefits are clearly present: *"**Customer-centric,** focused on delivering benefits and outcomes for <u>all</u> customers"* Our proposed knowledge sharing framework, detailed in *Section 4.4* above, outlines how the knowledge and customer benefits will be shared with customers, industry and regulators.

6 Theme 1: Enabling a Flexible Future

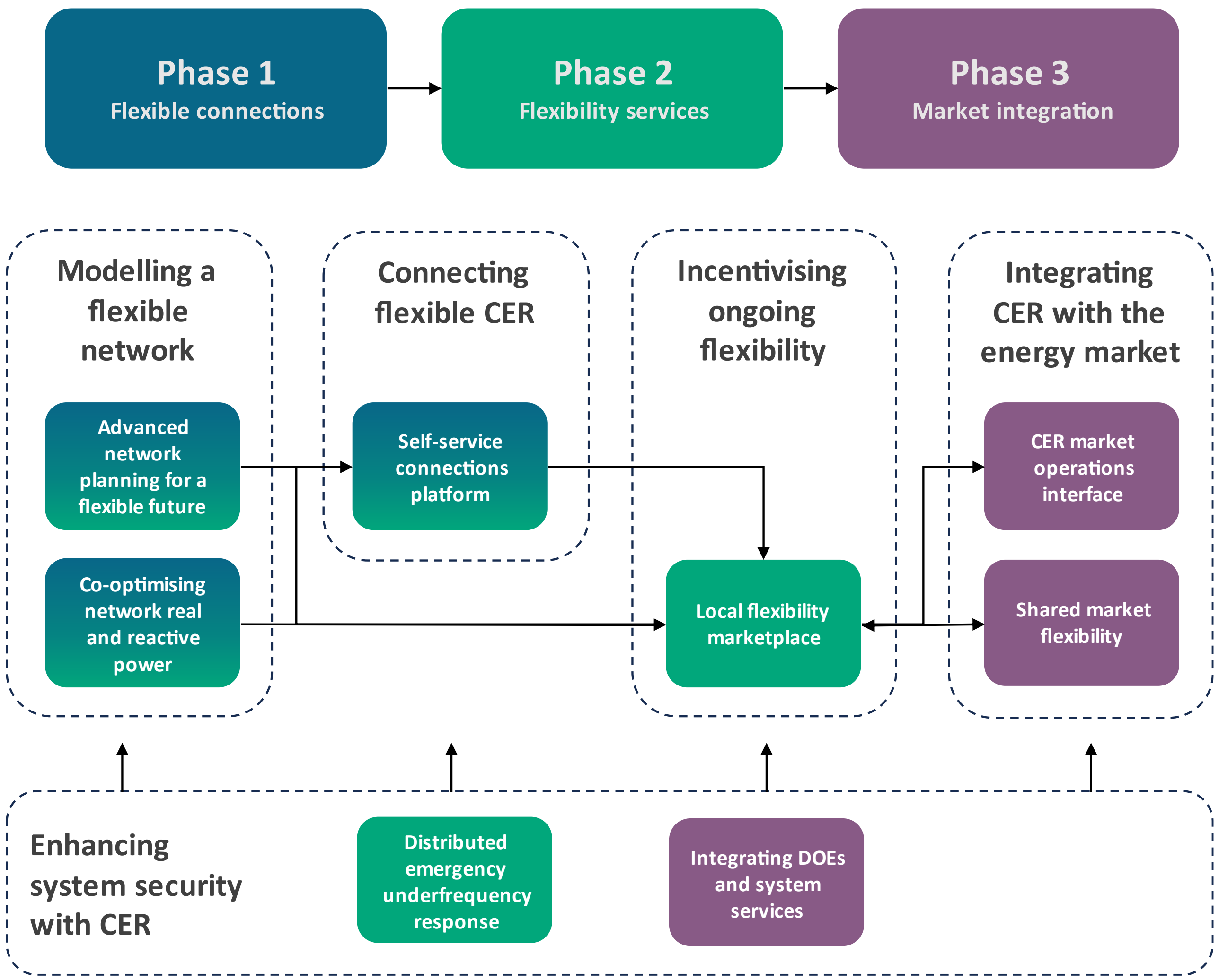
The projects to be undertaken via the *Enabling a Flexible Future* theme seek to build on the work undertaken in our 2020 – 2025 RCP and those proposed for our 2025 – 2030 RCP, namely the development of our Flexible Exports systems and associated customer offers, as well as our *Network Visibility*, *CER Integration* and *Demand Flexibility* programs.

These projects seek primarily to increase network utilisation and drive down unit costs for all consumers, but we consider that these projects will bring a number of wider benefits to the energy system, including:

- a reduction in wholesale energy prices;
- improved system security;
- improved customer experience; and
- a reduction in carbon emissions.

This theme contains projects across the three phases of flexibility described in *Section 3.1*, with the key functions outlined in *Figure 10*.

Figure 10 – functions of the projects in the Enabling a Flexible Future innovation theme



6.1 Advanced Network Planning for a Flexible Future trial

This project seeks to increase network utilisation by developing and piloting a combined High Voltage **(HV)** and LV planning tool for a CER-heavy network, based on SA Power Networks' LV Planning Engine and vendor HV modelling products. The tool would be developed and piloted for a portion of the distribution network.

This tool would allow for consideration of:

- the optimal balance between incentivising in demand flexibility and in network augmentation;
- the optimal locations to incentivise further CER installations to maximise network and market benefits;
- the customer experience under a range of flexible CER scenarios; and
- the effects of future pricing models on network demand and utilisation.

The outputs of the tool would inform the publication of network constraints to our *Local Flexibility Marketplace* outlined in *Section 6.4*, and would be further used as input to AEMO's Integrated System Plan (**ISP**), allowing for whole-of-system optimisation between transmission and distribution.

6.1.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- increasing volumes of distribution-connected resources are operating under a flexible connection, with projects such as our *Self-serve connections platform* and *Local Flexibility Marketplace* pilots incentivising further take-up of flexible connections to increase network utilisation;
- new services are increasingly being provided by CER, with our *Co-optimising network real and reactive power*, *Shared market flexibility and Integrating DOEs and system services* pilots opening up new or expanded access for CER to participate in flexibility services;
- current network planning tools are largely deterministic in nature, and do not allow for consideration of factors such as flexible connections, dynamic reactive power provision, customer response to advanced pricing signals or CER market participation;
- participation in flexibility services will become the dominant factor in determining the impact of a given resource on the network, and in-turn be the dominant factor in determining the amount of expenditure required to meet or manage demand;
- there is also an increasing need to consider a more holistic view of the energy system when planning the network, namely the interaction between our network's ability to host CER and the transmission planning function performed by AEMO via the ISP, via which required transmission projects are identified;
- the *Improving consideration of demand-side factors in the ISP* rule change[19], as well as the ISP Review[20], both initiated by the Energy & Climate Ministerial Council, are driving reforms to AEMO's planning process to require greater interaction between the planning of the distribution and transmission networks, as well as between the uptake of CER and the need for large-scale generation;
- these dynamic, integrated planning functions cannot be achieved with current network planning tools, which are instead designed to forecast 'snapshots' of the network such as peak and minimum demand events, and do not allow for more advanced probabilistic, scenario-based planning to account for demand flexibility and future pricing response.

19 https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp

20 https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan

The identified need for this project is thus to increase network utilisation and optimise whole-of-system planning across both the distribution and transmission networks by developing new end-to-end planning tools, co-optimising investments in CER flexibility with network augmentation and integrating these tools with AEMO's system planning function to realise a lowest whole-of-system cost view.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of standard control services (**SCS**) in clause 6.5.7(3)(iii) of the NER
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1); and
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER.

6.1.2 The project is genuinely innovative

Distribution network planning functions are well-established across DNSPs today but are focused purely on the medium voltage and HV networks. Management of the LV network has historically been a largely reactive exercise, with no centralised planning function and designs determined by regional depot practices and third-party developers. Design standards have consolidated these functions to an extent, but the majority of DNSPs still lack a genuine planning and management function for the LV network, namely due to the lack of network data and real-time visibility over this portion of the network.

The advent of smart meters and increasing network visibility has allowed for emerging solutions to modelling and planning the low-voltage network, such as SA Power Networks' *LV Planning Engine*, and in-house tool developed to support our activities to integrate CER into the LV network, as outlined in *5.7.6 CER Integration Business Case*, with the details of the tool provided in *5.7.7 CER Integration Modelling Methodology*.

While tools for planning the LV network are emerging, no integrated LV-to-HV planning tool exists today, nor does a tool to perform timeseries, scenario-based planning of the impact of CER, demand flexibility and future pricing models.

This pilot would seek to deliver:

- an uplift of our LV Planning Engine, integrating this in-house tool with vendor HV planning tools;
- capabilities for timeseries scenario-based modelling across the two tools, considering spatial CER uptake, CER response to network and retailer demand flexibility and orchestration programs, as well as future pricing models;
- co-optimisation within of network augmentation with incentivising CER flexibility, seeking to find the true lowest cost technically feasible solution to meet or manage demand;
- development of new techno-economic analysis capabilities to understand the most optimal locations for CER to be installed on the network, considering both network and wider market benefit;
- the outputs of the tool would be integrated into the *Self-serve connections platform*, *Co-optimising network real and reactive power* pilot and *Local Flexibility Marketplace* pilots, outlined in *Sections 6.2, 6.3* and *6.4* respectively, using the outputs of the modelling to inform actual connections, constraint response and procurement of non-network solutions;
- the outputs of the tool would be further integrated with AEMO's long-term planning process via the ISP, in order to realise:
    - co-optimisation of distribution and transmission network capacity; and
    - in future, co-optimisation of distributed generation with centralised generation, in efforts to realise the lowest whole-of-system cost to delivering the energy transition for customers.

SA Power Networks is best placed to undertake this pilot as our network operates with a world-leading volume of CER, which has spurred innovative responses such as our Flexible Exports and Energy Masters programs to enable demand flexibility from CER at scale, with these capabilities being productionised via *our 5.7.5 Demand Flexibility Business Case*. Integrating the response of these programs into long-term HV & LV network planning represents a logical progression, with SA Power Networks being the DNSP best placed to pilot such integrations due to our leading CER uptake, our pioneering roles in establishing demand flexibility and actively planning and managing our LV network.

6.1.3 Alternative funding sources are exhausted

This project may be eligible for co-funding, whether via the DMIAM or by pursuing funding from an ARENA grant:

- whilst the project does not directly concern demand management or the modification of the drivers of network demand, it will enable us to incorporate flexible CER into our long-term network planning, integrating the outputs of this planning into customer-facing flexibility tools and into AEMO's long-term planning via the ISP;
- however, the scale of this pilot would exhaust almost 20% of our DMIAM allowance for the period and would require further co-funding; and
- the nature of the pilot does not directly align with ARENA's current funding priorities with regard to flexible demand, in this case not being a direct demand flexibility product, but rather a means to integrate demand flexibility into our long-term planning and optimise the procurement of demand flexibility as an alternative to network augmentation. However, we would seek to explore and exhaust potential ARENA co-funding for this project prior to fully funding it via the Innovation Fund.

6.1.4 The project is prudently scaled

Implementation risks being addressed

This project seeks to fundamentally alter the methodology used for distribution network planning, namely by explicitly considering the behaviour of CER, customers response to retail pricing signals and our ability to procure flexibility services from CER to perform scenario-based network planning and minimise our reliance on network augmentation to meet demand.

Additionally, it will directly inform the inputs, modelling process and resultant recommendations of AEMO's ISP, a publication which is used as the guide for billions of dollars of energy infrastructure investment.

Avoiding significant volumes of planned network augmentation at both the distribution and transmission levels in favour of enabling and/or procuring flexibility from CER introduces significant risks which this project seeks to address, namely:

- forecast and/or planned volumes of CER flexibility do not eventuate, resulting in under-investment in network capacity and increased risk of enacting load-shedding to manage demand; and
- AEMO is unable to co-optimise between distribution and transmission network investments in the ISP model, resulting in inefficient investments and sub-optimal pricing outcomes for consumers.

Deciding on project scale

Piloting a new integrated LV and HV planning tool, co-optimising between network augmentation and flexibility services from CER, with system services will allow us to explore the potential of this concept to support system security whilst managing the risks of potential underinvestment in network capacity and generation. The pilot seeks to understand the validity of the proposed tool prior to a potential rollout of a more developed tool to the entire network, as well as a more fulsome integration with AEMO's long-term system planning process via the ISP.

The scope of the pilot would be limited to planning of the network below 2 transmission connection points, covering all downstream distribution network assets and customers (approximately 5% of our network).

This pilot is appropriately scaled as the inclusion of 2 transmission connection points will allow for the consideration of variations in:

- network design and configuration;
- customer numbers, types and behaviours; and
- CER uptake and participation in demand flexibility or market orchestration.

The proposed scale also allows for detailed consideration of both the LV and HV networks downstream of those points, including any required field scoping for data collection to uplift our network models, with a wider scope limiting our ability to perform fulsome data capture. It also aligns with AEMO's current consideration of the South Australian energy system within the ISP model, which models two transmission nodes for the state network.

This pilot would run over a period of 2 years, beginning in Q3 of 2025. The proposed planning tool would serve as an input to several other innovation projects, including the *Self-serve connections platform*, *Co-optimising network real and reactive power* pilot and *Local Flexibility Marketplace* pilots, outlined in *Sections 6.2, 6.3* and *6.4* respectively, with efficient outcomes from these projects each reliant on the delivery of the proposed planning tool.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- quantified reductions in network augmentation forecasts based on increased reliance on demand flexibility; and

- the ability of AEMO to ingest forecasts of distribution network constraints at the transmission-distribution interface.

A wider deployment of this tool would see us utilise it for planning across the entire network, integrating our existing HV and LV planning processes and productionising both the newly developed systems and probabilistic planning criteria for the procurement of flexibility services. Further engagement with AEMO would be undertaken on current reforms seeking for greater co-optimisation of distributed generation and distribution network capacity with utility-scale generation and transmission network capacity within the ISP, seeking to productionise the integrations into AEMO's ISP model and realise full whole-of-system co-optimisation.

6.1.5 The project aims to drive long term consumer benefits

Developing and piloting holistic network planning capabilities to co-optimise the procurement of flexibility services from CER and investments in network augmentation, and integrating the outputs of this modelling with AEMO's long-term system planning will deliver benefits to all energy consumers by way of:

- **increased network utilisation** and **avoided network augmentation** through co-optimisation of flexibility services with network augmentation, as well as co-optimisation of investments across all levels of the energy system;
    - developing holistic models from the LV network through to the transmission network interface will allow for truly optimised network planning to be undertaken, providing an end-to-end view of how enabling flexibility on the LV network can support demand at higher

levels of the network, including avoiding investments in transmission capacity, centralised generation and storage through integration with AEMO's ISP; and

- these models will create a fulsome view of utilisation across all levels of the network, and determine where investment in removing LV constraints may be justified in order to fully utilise the HV or transmission networks.

▪ **reduced wholesale energy pricing** and a **reduction in energy system emissions** through optimised CER exports;

- developing a holistic view of network management from an individual customer through to the transmission network will allow for the benefits of enabling additional CER exports to be quantified at all levels of the system, including how CER can be leveraged to resolve constraints at higher levels of the network (with this actioned via the *Local Flexibility Marketplace*; and
- optimised distribution-level balances of flexible CER and network augmentation can be provided to AEMO for consideration in the ISP, which can in-turn optimise between further investment in unlocking capacity for CER with traditional investment in large-scale generation, with more optimal investments driving down generation costs and in-turn wholesale pricing.

6.1.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $1.09 million of capex, and $0.37 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to plan a flexible network, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.1.4.*

A full cost breakdown, including itemised estimates, is included on the *7.1. Flex Planning* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. All costs for the project, however, have been based on our actual costs incurred to deliver projects of a similar nature in past, in this case being based on:

- the costs to design and develop our in-house *LV Planning Engine*; and
- market modelling conducted with consultant support for our extension of the customer export curtailment value (**CECV**).

Efficiencies in delivery have been identified with *7.3. Self-Serve Connections Platform Pilot* and *7.4. Local Flexibility Marketplace Pilot,* as a result of which we have reduced our estimated effort for network model tuning and maintenance.

6.2 Co-optimising network real and reactive power trial

This project seeks to increase network utilisation by developing and piloting systems to co-optimise the use of active and reactive power to resolve network constraints. These systems would be integrated into our connections process via our *Self-serve connections platform pilot* and into demand flexibility via our *Local flexibility marketplace pilot*, outlined in Sections *6.3* and *6.4* respectively.

6.2.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- network constraints arise in the form of thermal limits on network assets and voltage fluctuations beyond regulatory bounds at the point of customer supply, with these constraints currently resolved by modifying active power flows on the network to a point below the thermal rating of a given asset, or to the point where voltage at the supply point for each downstream customer is returned to an acceptable level;
- modifying active power flows is achieved by applying site-level import or export limits via a DOE, upon receipt of which a site can determine how to best respond, either by changing the output of a solar PV inverter, battery system, EV charger or other controlled device;
- while active power is used as the primary resolution to network constraints, modifying network *reactive power* is a more efficient alternative, but one that has largely not been explored to date due to limitations of DNSP systems ability to calculate the required reactive power response, and for customer equipment to receive and enact the response;
- the use of reactive power response from CER can directly support network thermal and voltage compliance, but has a reduced impact on customers when compared to active power, which represents a real reduction in the volume of energy exported;
- by co-optimising CER active and reactive power response to a constraint via a DOE, network security and quality-of-supply can be maintained whilst reducing the need to curtail CER exports and hence reducing the impact on customers.

The identified need for this project is thus to respond to the fact that co-optimising reactive power response from CER with traditional active power response presents an opportunity to improve and optimise the utilisation of distribution network hosting capacity, in order to:

- maximise the ability of CER to import from or export to the network, reducing reliance on large-scale generation and hence reducing wholesale energy costs and energy system emissions, as well as improving the ability of customers to access market revenue via their CER; and
- improve the voltage performance of our network by optimising reactive power flows at a more granular level, improving the quality-of-supply of our network and hence reducing the impacts of overvoltage on customer equipment and their experience.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER;
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1);
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.2.2 The project is genuinely innovative

Reactive power compensation is applied in several areas of network operations today, namely:

- reactors and capacitor banks installed on the medium and high voltage networks;
- static-VAr compensators (STATCOM) installed on the low-voltage network; and
- the Volt-VAr power-quality response mode required for inverter-based generation as per AS/NZ 4777.2 2020.

Each of these control mechanisms are primarily addressing localised voltage constraints, with reactors and capacitor banks operating via a SCADA controlled VAr setpoint, whilst STATCOMs and inverters with the Volt-VAr response mode operate under a P-Q droop curve, based on the voltage measured at the device.

However, no DNSP has to date implemented a solution to *network wide* reactive power optimisation, utilising reactive power response from distributed CER to resolve upstream network constraints, and hence minimise the active power impact on all upstream resources.

This project aims to pilot the deployment of:

- a Volt-VAr-Watt Optimisation (**VVWO**) module within our Advanced Distribution Management System (**ADMS**) environment;
- an exploratory network modelling exercise to understand the efficacy of distributed reactive power provision in resolving network constraints;
- models to calculate AS/NZ477.2 Volt-VAr curves optimised to the site-level;
- extensions of our CER management systems, initially designed and deployed to support Flexible Exports, to schedule and dispatch reactive power DOEs; and
- a field-trial with 2 CER original equipment manufacturers (**OEMs**), deploying reactive-power DOEs to 5 commercial customers and 50 residential customers.

SA Power Networks is best placed to undertake this pilot as maintaining network quality-of-supply and providing efficient access to export services as desired by customers is within the scope of our role as a DNSP, and more specifically, within the scope of our SCS and in particular, our 'Common distribution service' as per the AER's Service Classifications.

Co-optimising active and reactive power response via DOEs is of benefit to all DNSPs, but only SA Power Networks is able currently to pilot the concept as:

- our world-leading implementation of DOEs via our Flexible Exports program has ensured that legislation, standards and systems are already in place in South Australia to enable standardised communication of DOEs to all new CER installations; and
- our deployment of a Distributed Energy Resources Management System (**DERMS**) within our ADMS is the first of its kind and provides foundational capabilities the foundation to establish VVWO capabilities for CER.

6.2.3 Alternative funding sources are exhausted

This project may be eligible for co-funding, via the DMIAM or by pursuing funding from an ARENA grant, however:

- the scale of this pilot would exhaust almost 50% of our DMIAM allowance for the RCP, and would required further co-funding; and
- the nature of the pilot does not directly align with ARENA's current funding priorities with regard to flexible demand, in this case not being a direct demand flexibility product, but rather a means to

optimise the value of other demand flexibility products by way of unlocking greater network capacity for active power response from CER. However, we would seek to explore and exhaust potential ARENA co-funding for this project prior to fully funding it via the Innovation Fund.

6.2.4 The project is prudently scaled

Implementation risks being addressed

This project seeks to directly alter the methodology used to determine limits provided to CER via a DOE, with the provision of DOEs increasingly becoming our core tool for managing network quality of supply. Whilst reducing the volume of active power curtailment that we require in favour of additional provision of reactive power response from CER in response to network constraints poses significant benefits, doing so introduces a number of additional risks that this project seeks to address, namely:

- inability of our network models to accurately determine the optimal balance of active and reactive power response to resolve a given constraint, leading to inefficient curtailment of CER exports;
- inability of CER to provide the required level of reactive power support under different local and system-level operating conditions; and
- a lack of appropriate customer-facing offers required to enable customers to opt-in to the provision of additional reactive power support, whether via a direct relationship with us or via a third-party.

Deciding on project scale

Piloting a co-optimised approach to managing network constraints using both active and reactive power will allow us to explore the implementation risks without compromising our ability to safely manage our network within its technical limits, ensuring a reliable and high-quality supply to all customers. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout to the entire network of a more developed system, as well as a broader customer-facing offer.

Specifically, the scope of the pilot would be limited to a field-trial with 2 CER OEMs, deploying reactive-power DOEs to 5 commercial customers and 50 residential customers.

This trial is appropriately scaled as it will allow for sufficient customer participation to capture variations in:

- customer type and behaviour;
- CER types and participation in other demand flexibility or market orchestration programs; and
- geographical diversity in PV production, and hence the ability to utilise PV inverters for reactive power response.

Including multiple OEMs in the trial will ensure that the new capabilities for CER to receive reactive power controls are scalable across vendors, with any new technical requirements developed being consistent with industry best practice.

The proposed scale also allows for detailed consideration of both the LV and HV networks downstream of those points, including any required field scoping for data collection to uplift our network models, with a wider scope limiting our ability to perform fulsome data capture. It also aligns with AEMO's current consideration of the South Australian energy system within the ISP model, which models two transmission nodes for the state network.

This project would be run over a 2-year period, beginning in Q2 2026. Delivery of co-optimised reactive power response from CER is:

- reliant on the establishment of *7.4 Local Flexibility Marketplace pilot*;
- supported by the new shared communications pathway demonstrated in *7.6. Shared market flexibility pilot*; and

- directly feeds into the new network planning models developed in *7.1. Advanced Network Planning for a Flexible Future.*

Success factors and pathway from trial to BAU

The success criteria for this project, to be further expanded at the project implementation stage include:

- the proven ability of the procured reactive power response to better manage voltage performance, quality-of-supply and utilisation of network hosting capacity;
- quantified reductions in active power curtailment, and hence additional export and/or import volumes unlocked for CER customers that would otherwise be constrained; and
- feedback solicited from participating pilot customers and OEMs regarding the feasibility of the technical solution to roll-out to a wider number of customers and devices.

6.2.5 The project aims to drive long term consumer benefits

Development of co-optimised active and reactive power DOEs for CER will drive significant long-term benefits to all electricity consumer, including:

- **increased network utilisation** and **avoided network augmentation** via increased reactive power voltage support:
  - by procuring reactive power support from CER, network voltage performance can be improved and the need to curtail CER exports or imports to meet voltage constraints will be reduced;
  - this will in turn increases the ability of CER to utilise network hosting capacity and deliver increased service levels to customers without the need for network augmentation;
- **reduced wholesale energy pricing**, and **increased value of emissions reduction** through increased CER exports by increasing the ability of CER to utilise network hosting capacity and in-turn increasing the total volume of CER export which will:
  - reduce wholesale energy costs for all consumers as measured by the AER's Customer Export Curtailment Value **(CECV);**
  - increase the Value of Emissions Reduction (**VER**) as measured by the AER's VER approach;
- **Expanded revenue streams for CER owners** through increased CER exports:
  - increasing the ability of CER to utilise network hosting capacity will allow market-active CER, whether directly or via a VPP to access market revenue; and
  - additionally, the increased level of reactive power support provided by CER would be in exchange for direct network payments, facilitated through the Local Flexibility Marketplace outlined in *Section 6.4.*

6.2.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $2.83 million of capex, and $0.32 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to co-optimise constraint remediation using real and reactive power, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.2.4.*

A full cost breakdown, including itemised estimates, is included on the *7.2. Real and Reactive Power* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- the implementation of our ADMS DERMS trial; and
- exploratory Volt-VAr power-flow modelling conducted in conjunction with the University of South Australia.

Efficiencies in delivery have been identified with 7.1. *Advanced Network Planning for a Flexible Future* trial, *7.3. Self-Serve Connections Platform Pilot* and *7.4. Local Flexibility Marketplace Pilot,* as a result of which we have reduced our estimated effort:

- technical design and industry engagement on an extension of the CSIP-AUS communications protocol;
- an uplift of our core CER management systems for generating, scheduling and dispatching controls from our models through to CER;
- an uplift of our IEEE2030.5 CSIP-AUS server to handle reactive power controls, with this server being the public-facing interface through which all CER controls are dispatched and responses received; and
- network model tuning and maintenance.

6.3 Self-Serve Connections Platform Pilot

This project seeks to pilot a *self-serve connections platform* allowing parties proposing to connect to the distribution network to receive indications of:

- available network capacity across *all* levels of the network;
- service levels experienced under a flexible connection, including the frequency and magnitude of curtailment; and
- costs and estimated timeframes to connect at a given location, for fixed or flexible connections.

The determination of network capacity in the platform would be based on the outputs of our *Advanced network planning for a flexible future pilot*, as outlined in *Section 6.1.*

6.3.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- South Australia is at the forefront of the energy transition, with a world leading penetration of distribution connected CER. Increasing volumes of large resources are being connected under the negotiated connections framework, requiring a connections assessment to determine the impact of a given connection on the local and wider network;
- connection assessments can be time-consuming and costly, for both DNSPs and connecting customers. A customer wishing to connect a large resource to the network, either a load or generator, has little indication of where the network may have capacity until the assessment is undertaken;
- depending on the nature of the resource being connected, the costs of a network connection may form a significant part of the project's overall cost, but also may vary significantly depending on where the connection is located on the network. This presents an optimisation problem – connecting proponents can determine a location with suitable real estate and supporting infrastructure, but they cannot determine whether that location also has sufficient network capacity to host their asset.
- this can lead to a frustrating customer experience, where several feasibility studies may need to be undertaken by a developer before a suitable location is selected, with a unique connections assessment performed by the DNSP for each study;
- traditional connections to the distribution network have been 'fixed' connections – a customer will request a given capacity, whether for importing from or exporting to the network, and the DNSP will model the impact of that connection on their network, largely assuming that the requested capacity is required at all times. In practice though an increasing number of new connections have some inherent flexibility in their operations:
    - a key example is a large battery, which has a reduced need for 'guaranteed' network capacity when compared to traditional loads, instead requiring firm load only for cooling, control and communication systems, while the battery output is entirely dependent on market conditions and the operator's bid strategy; and
    - such connections often have lower requirements on real-estate and supporting infrastructure, and instead seek the lowest-cost network connection available; and
    - *flexible connections* are a significant opportunity for such sites, where the asset can be connected to the *existing* network, at minimal cost and without waiting for network augmentation to be performed. In exchange, the site would operate under a DOE, receiving a time-varying import and export limit from the DNSP reflecting the real-time limits of the network.
- this presents a further optimisation problem for proponents connecting a battery to the distribution network – one of trading off lost market revenue in exchange for curtailing the batteries output due

to available network capacity. The operator of such a battery, however, currently has no way to understand what portion of time a given amount of network capacity would be available and allocated to their asset under a flexible connection – i.e. what their *service level* would be. This issue is not unique to battery connections, but to any asset potentially suitable for a flexible connection.

The identified need is therefore to respond to the fact that customers and their agents proposing to connect to the distribution network, need location-specific and dynamic information on the capacity of the network, and the ability to self-serve their access to this information, in order to:

- make an informed and efficient choice as to where on distribution network to connect, given the differing implications for costs to the network and the proponent based on the networks' available capacity on a location specific basis;
- make informed decisions about potentially flexible connection offers, where connection proponents have flexibility in their operations, with these offers for flexible management of export and load connections helping to maximise network utilisation, minimising network costs of augmentation as well as connection costs for the proponent; and
- minimise connection process and administrative costs.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER;
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1);
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.3.2 The project is genuinely innovative

This project would leverage work already undertaken in the previous RCP, namely:

- model-based identification of network hosting capacity for the purpose of enabling flexible exports for basic connections;
- development of an in-house low-voltage planning tool (the LV Planning Engine) for the purpose of forecasting our CER integration expenditure for the 2025 – 2030 RCP; and
- trials of flexible connections for negotiated connections, understanding the suitability of various connecting assets to operate under such a connection and the foundational DNSP systems required to enable them.

These foundational initiatives would be expanded in order to:

- develop a holistic approach to determining network capacity across the LV, MV and HV networks, by linking models to understand the upstream effects of a given connection at all levels of the network;
- develop models to calculate the service level experienced under a flexible connection for a given connecting resource, allowing proponents to upload their load profile or select from a library of templates;
- develop an interactive, publicly accessible mapping interface to provide indicative network capacity and constraint information to connecting proponents (in addition to being used internally); and
- replace the need for preliminary assessments of negotiated connections, which today are performed at a cost to the customer of approximately $5000, with these assessments instead occurring instantly at the distribution transformer, 11kV feeder, substation transformer and sub-transmission networks.

Providing publicly accessible data on network capacity of some form is not in itself innovative as DNSPs, including ourselves, currently publish network capacity data. However, this data is currently limited to:

- timeseries power-flow data (MW, MVAr, MVA) aggregated to the zone substation level from downstream supervisory control and data acquisition (**SCADA**) readings; and
- feeder level available import and export hosting capacity (MVA), based on a high level, simplified network assessment of that feeder in isolation.

This data is currently made available for download and displayed on an interactive map via our Distribution Annual Planning Report (**DAPR**) portal[21], with other DNSPs maintaining a similar web-portal. Our approach to providing this data is already leading, as our understanding is that we are the only DNSP currently providing indications of available feeder-level import and export hosting capacity. However, data currently made available via the DAPR portal does not provide data granular enough, or up-to-date enough to address the needs of connecting proponents, as:

- time-series power-flow data aggregated to the substation level is not of use to proponents connecting downstream of that substation, as constraints may vary significantly across the downstream feeders; and
- hosting capacity aggregated to the feeder level, and updated annually per the DAPR timeframes is not of use to proponents connecting downstream, noting:
    - available hosting capacity varies significantly across a feeder, and changes frequently over time;
    - utilisation of that available hosting capacity depends on the behavioural profile of the connecting asset;
    - hosting capacity indications account for the thermal limitations of upstream assets only, ignoring potential voltage constraints;
    - it does not allow for scenario-based assessments which consider speculative generation connection enquiries on a segment of that feeder
- flexible connections are not considered, despite being a critical element of the future energy system; and
- no indication of costs or connection timeframes is provided, with a preliminary connections assessment still being required.

In summary, the proposed self-service connections platform is genuinely innovative by virtue of being the first attempt at a DNSP at:

- developing a truly holistic view of network capacity, from the LV distribution transformer through to the transmission connection point;
- considering both thermal and voltage constraints in the capacity assessments;
- providing indications of the service level experienced under a flexible connection, namely the frequency and magnitude of curtailment, tailored to a behavioural profile uploaded by the proponent; and
- providing indicative costs and timeframes for connection in an automated fashion, removing the need for preliminary connection assessments entirely (currently at an approximate cost to customers of $5000 per assessment).
    - while the self-serve connections platform would serve as a long-term replacement for the preliminary connections assessment process, pilot participants would still have a

[21] https://dapr.sapowernetworks.com.au/

preliminary assessment performed by SA Power Networks, but at no cost to them (i.e. they would be excluded from the typical $5k charge).

SA Power Networks is best placed to undertake this pilot as facilitating efficient connections to the distribution network falls within the scope of our role as a DNSP, and more specifically, within the scope of our SCSs and in particular, our 'Common distribution service' and our 'Connection services' as per the AER's Service Classifications.

Additionally, the consideration of flexible connections within the platform is enabled by the existence of demand flexibility products, which our Flexible Exports program has implemented in full for export-only connections, and our Energy Masters program seeks to expand to the load-side, with the fulsome implementation of these flexible connection offers outlined in our *Attachment 17 - Connections Policy.* As the only DNSP with a production implementation of flexible connections for both residential and commercial customers, the development of a self-serve connections platform centred on flexibility is most suited to SA Power Networks.

6.3.3 Alternative funding sources are exhausted

There are no viable alternative funding sources for this project at this time, on the basis that:

- it does not align with the scope of the DMIAM as it does not concern demand management or the modification of the drivers of network demand. The project instead aims to improve the efficiency of the connections process, directing proponents to areas of the network with spare capacity and encouraging better utilisation of the network through flexible connections; and
- it does not align with ARENA's funding objectives, as per their current funding programs[22]. ARENA's strategic priorities for the Advancing Renewables Program include optimising the transition to renewable energy, within which ARENA seeks to 'demonstrate the value and viability of flexible demand' and 'improve the enablers of flexible demand,' in this case referring to technical standards, network tariffs and customer-facing flexibility products. Whilst this project seeks to better support customers in their selection of a flexible connection, it does not directly seek to develop or improve a flexible demand product.

6.3.4 The project is prudently scaled

Implementation risks being addressed

Determining the impact of a new connection on the network is critical to ensuring that we can continue to operate a stable and reliable power system. As such, it is not prudent to transition to an automated connections process without thorough exploration of:

- the capabilities of our network model;
- the upfront information regarding service levels, costs and connection timeframes required by customers to make an informed decision; and
- required changes to our internal & customer-facing processes, standards and technical requirements.

Selection of project scale

Piloting the self-serve connections platform will allow us to explore the implementation risk without compromising the quality of the connections experience we provide our customers. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout to a wider user-base of a more developed product.

[22] https://arena.gov.au/funding/

Specifically, the scope of the pilot would be prudently limited to:

- 10 transmission connection points and all downstream assets (approximately 25% of our network); and
- allow access to at least a pilot connections user group (rather than being made public), with the group selected primarily from our Connections Working Group and targeted to proponents seeking flexible connections.

This pilot is appropriately scaled as the inclusion of 10 transmission connection points will allow for sufficient coverage of:

- diversity of connection types and sizes;
- type, age and condition of network assets under which connections are sought;
- connecting proponents, allowing for coverage of large renewables developers, EV charging operators and residential builders.

A smaller scale pilot would risk insufficient numbers connections applications to the trial area or diversity in those connections, hindering our ability to generate useful learnings and limiting the benefits of the project.

This project would be run over a 3-year period, beginning in quarter 2 2026. Development of a self-serve connections platform is:

- reliant on the establishment of advanced network planning capabilities in *7.1. Advanced Network Planning for a Flexible Future trial*;
- an input to those same new network planning capabilities, with automated connections assessments leveraging the developed tools; and
- an input to the *7.4. Local Flexibility Marketplace pilot,* with automated assessments performed on new non-network solutions seeking to resolve market constraints.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project planning and implementation phase, include:

- feedback solicited from participating pilot customers, i.e. connecting proponents who have received indicative network capacity, service levels, costs and connections timeframes;
- comparison of the automated and model-based approach, versus our traditional manual approach, to preliminary assessments; and
- quantified reductions in the cost incurred to us to undertake a preliminary connections assessment, and in the time taken to provide an offer to a connecting proponent.

Subject to the success of the pilot, we would seek to:

- expand the portions of the network considered within the platform, and the user group that access is provided to, via a progressive rollout;
- establish a user reference group to gather continual industry feedback on the usefulness of the product, as well as any potential uplifts required to supporting emerging customer needs; and
- still conduct preliminary connections assessments, but at no cost to customers, until such time that internal confidence has been developed in the viability of the tool to fully replace these assessments.

6.3.5 The project aims to drive long term consumer benefits

A self-serve connections platform for connecting proponents to receive automated preliminary connections assessments will drive significant long-term benefits to all electricity consumers including:

- **increased network utilisation** and **avoided network augmentation** via customers' use of more optimal connection locations:
  - as outlined in section 6.3.1, proponents seeking to connect to the distribution network today are unable to determine an 'optimal' location to connect, where a suitable location is available for their project and the local network is not fully utilised;
  - by proactively directing proponents to these locations, the surrounding network can be greater utilised and driving down network unit pricing for all customers.
- **reduced wholesale energy pricing** via cheaper, faster connections and hence lower generation costs:
  - by connecting generation to the network in less time and at a lower cost, the total development costs for a distribution-connected generator will be significantly reduced;
  - lower upfront generation costs will in-turn lead to lower energy market bid for scheduled generators, delivering a long-term reduction in wholesale energy costs for all customers. While there are few scheduled generators currently connected to the distribution network, we consider that the *Integrating price-responsive resources into the NEM* rule change[23] will lead to a significant number of scheduled generators on our network, each with the ability to set market price.
- **improved customer experience and time saving** from more efficient connections:
  - feedback from our customer forums, including our Connections Working Group, has identified the time and costs involved with seeking a network connection as a barrier to a more efficient renewables development market; and
  - by automating the preliminary assessment process, we consider that the experience of a developer seeking a network connection will be significantly improved, and that this will also be reflected in improved savings in the customer value of time[24].
- **increased value of emissions reduction** for all consumers, via lower cost connections incentivising more renewables:
  - reducing wholesale energy pricing, particularly given South Australia's proliferation of negative pricing, has led to increasing difficulty in developing an economic business case for new renewable generation. The costs of a network connection can increasingly 'make-or-break' the case for a given generator, with several proponents having shared such experiences first-hand; and
  - by significantly lowering upfront connection costs, and incentivising flexible connections via ongoing tariff discounts, more developers will be able to develop an economic business case for new renewable generation, in turn lowering overall system emissions.

[23] https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

[24] This is another commonly accepted value metric within regulatory decision making, as guided by Commonwealth Government derived valuation approaches.

6.3.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $1.81 million of capex, and $0.39 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to develop a self-service connections platform, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.3.4.*

A full cost breakdown, including itemised estimates, is included on the *7.3. Self-Serve Connections* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- indicative discussions with vendors;
- development costs for our in-house LV Planning Engine; and
- modelling effort to perform simple assessments displayed on our DAPR portal.

Efficiencies in delivery have been identified with *7.1. Advanced Network Planning for a Flexible Future trial*, *7.2. Co-optimising network real and reactive power trial* and *7.4. Local Flexibility Marketplace Pilot,* as a result of which we have reduced our estimated efforts for:

- network model tuning and maintenance;
- an uplift of our LV Planning Engine and an uplift of our vendor HV modelling tools.

6.4 Local Flexibility Marketplace pilot

This project seeks to increase network utilisation by piloting a flexibility marketplace, through which:

- constraints identified via our advanced network planning tools can be automatically published, leveraging the *Advanced Network Planning for a Flexible Future* trial;
- published constraints can be bid for by participants in a series of distribution markets, with options for response including both active and reactive power, this response having been co-optimised in our *Co-optimising network active and reactive power* pilot;
- response to a constraint can be settled, payments managed and resources dispatched; and
- emergency underfrequency enrolment from CER can be managed, supporting our *Distributed emergency underfrequency response* pilot.

This marketplace would be co-operated by ourselves and ElectraNet as the South Australian transmission network service provider (**TNSP**), serving as the primary customer-facing portal through which all paid flexibility services can be managed across both the distribution and transmission networks.

6.4.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- constraints exist across the distribution network today, limiting the ability of new load and generation to connect to the network;
- constraints have historically been resolved by network augmentation, although resolution by DOEs is becoming an increasingly viable option for export constraints on the LV network;
- large constraints requiring expenditure above $6 million[25] to resolve will go through the Regulatory Investment Test – Distribution (**RIT-D**), through which we will seek a non-network solution prior to pursuing network augmentation;
    - up to now, we have been unable to procure significant volumes of non-network solutions to avoid RIT-D augmentation, but we consider that the market for these solutions is expanding and that they are becoming increasingly available;
- emerging reward-based flexibility services, such as those proposed in our *Distributed emergency underfrequency response* pilot and *Co-optimising network active and reactive power* pilot will need a customer-facing product through which enrolment in paid network services can be managed, as well as settlement and dispatch of those services;
- there is also an emerging opportunity to work closely with transmission providers to manage transmission constraints using response on the distribution network, using the outputs of the integrated modelling approach developed in our *Advanced Network Planning for a Flexible Future* trial; and
- creating an increasing number of customer and industry facing flexibility services without a consistent interface to access those services will hinder their effectiveness, with complex participation processes likely to reduce the number of participants.

The identified need is therefore to:

- improve the visibility of network constraints and the accessibility of providing a solution to those constraints;

[25] The RIT-D threshold will increase to $7 million 1 January 2025

- create a consistent technical approach for the management of constraints across all levels of both the distribution and transmission networks;
- integrate current and future flexibility services into a single, customer and industry facing platform;
- create a central system for managing the procurement, settlement, dispatch and compliance of non-network solutions across all levels of the energy system, including both the distribution and transmission networks.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1);
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.4.2 The project is genuinely innovative

Procurement of non-network solutions via an online marketplace is a concept currently deployed at-scale in the United Kingdom, namely by UK Power Networks and National Grid Electricity System Operator (**ESO**). A trial of this concept is also underway by Powercor in Australia, as an extension of the annual planning process seeking non-network solutions to identify RIT-D constraints and LV constraints as identified in the DAPR.

However, our proposed deployment of a flexibility marketplace differs significantly from those currently in place, and is therefore innovative on the basis that:

- this pilot would not seek to purely publish long-term, large-scale constraints (i.e. projects at the RIT-D scale identified via the DAPR), but would instead seek to uplift a flexibility marketplace platform to develop real-time integrations with our DOE generation systems, as well as the advanced planning tools developed through our *Advanced Network Planning for a Flexible Future* pilot;
- the procurement of short-term response to network constraints via the flexibility marketplace would be considered in our DOE generation systems, by first seeking a paid response to a constraint from the market where economic to do so, before requesting response from CER via DOEs to manage any residual constraints not settled via the marketplace;
    - this co-optimisation of paid and unpaid flexibility, augmentation already having been considered via our *Advanced Network Planning for a Flexible Future* pilot, would use the augmentation costs of a constraint, the value of curtailed CER as per the CECV and the costs to procure market flexibility in order to provide the lowest cost solution to meeting demand;
    - this three-way optimisation is a concept not yet explored in any flexibility deployment;
- treatment of both distribution and transmission network constraints within the same platform, and accounting for the ability of customer response at the LV level to resolve a transmission level constraint is unprecedented and would represent significant progress towards optimising network operations in a whole-of-system manner.

SA Power Networks is best placed to undertake this pilot as the management of demand within network capacity falls within the scope of our role as a DNSP, and more specifically, within the scope of our SCS and in particular, our ‘Common distribution service’ as per the AER’s Service Classification.

Additionally, the procurement of flexibility services from CER requires the establishment of a ‘critical mass’ of flexible resources to respond to the market. More than 30% of residential customers with a battery in

South Australia currently choose to participate in orchestration via 18 active virtual power plants (VPPs) in South Australia. The number of VPPs operating in South Australia, and the volume of customers participating in them, are the highest in the nation, making our network the optimal location to deploy this pilot. The development of a fully automated, market-to-device platform for real-time constraints requires established DNSP-to-CER communications systems, which we consider to only be in place in South Australia, having been implemented via our Flexible Exports program.

6.4.3 Alternative funding sources are exhausted

This project may be eligible for co-funding, whether via the DMIAM or through pursuing funding from an ARENA grant. Additionally, we consider that as a joint interface with ElectraNet, there may be an opportunity to co-fund the project using their DMIAM. Key funding considerations addressed for this project include:

- while the project does not directly concern demand management or the modification of the drivers of network demand, instead focusing on streamlining the process for participation in reward-based demand flexibility by providing access to multiple distribution and transmission level markets via a singular interface, it will increase overall participation in demand flexibility and hence address network demand to an extent;
- the scale of this pilot would exhaust more than 60% of our DMIAM allowance for the period, and would require further co-funding;
- ElectraNet’s ability to co-fund this project will be dependent on their available DMIAM allowance and willingness to contribute; and
- given this pilot seeks to integrate a commercially available flexibility marketplace into a suite of new network flexibility services, ARENA may consider the technology involved to be sufficiently mature so as to fall outside of the scope of their funding priorities in accelerating new technology development.

6.4.4 The project is prudently scaled

Implementation risks being addressed

This project seeks to offset significant amounts of network augmentation via the procurement, settlement and dispatch of non-network solutions via an automated flexibility marketplace. Constraints available via this marketplace would be real network constraints, ranging from long-term, months-ahead constraints through to intra-day constraints. Solutions procured via the marketplace will play a critical role in supporting our ability to maintain a reliable network whilst avoiding cost increases, but will introduce additional risks that the pilot seeks to address, namely:

- non-conformance to solutions offered by flexibility service providers, resulting in a breach of network limits and potential outages; and
- failure of the automated procurement, settlement or dispatch functions of the marketplace, leading to insufficient response to a constraint and hence a network overload and outage; and
- insufficient enrolment of flexibility service providers to ensure a competitive market for non-network solutions.

Deciding on project scale

Piloting a local flexibility marketplace will allow us to explore the potential for significant volumes of network augmentation to be avoided and existing network better utilised by signalling network constraints to the market and procuring, settling and dispatching solutions to those constraints. The pilot must ensure that we can do so without compromising our ability to maintain power flows on the distribution network within safe operating limits, as well as ensuring that upstream transmission network limits are adhered to. The pilot seeks to understand the validity of the proposed marketplace within the context of the South Australian distribution network by way of a small-scale deployment with minimal technical uplift, prior to a wider rollout of a more production platform to a statewide audience.

Specifically, the scope of the pilot would be limited to:

- constraints covering four constrained transmission connection points, including all downstream distribution network assets *and* upstream transmission network assets;
- flexibility markets would include active and reactive power support, as well as underfrequency response, aligned with the pilot scope of our *Co-optimising network real and reactive power* and *Distributed emergency underfrequency response* pilots; and
- constraints would be generated from pilot internal planning tools developed in our *Advanced network planning for a flexible future* pilot, and not integrated with our operational ADMS DERMS system.

This pilot is appropriately scaled as the consideration of four constrained transmission connection points will ensure that:

- sufficient volume of constraints are included in the marketplace;
- sufficient diversity in constraints is present, including voltage, thermal and underfrequency constraints from the LV through to the sub-transmission networks;
- sufficient VPP-enrolled customers and/or non-network solutions such as large batteries or commercial flexible customers are able to respond to constraints;
- diversity in flexibility service providers, such as energy retailers or VPP operators is present, ensuring that the ability of the entire market to respond to constraints in real-time can be determined.

This project would be run over a period of three years, beginning in quarter 2 2026. Development of a flexibility marketplace is:

- required to enable the customer-facing flexibility offers developed through *7.2. Co-optimisation of network real and reactive power, 7.7 Integrating DOEs and system services* and *7.8. Distributed Emergency Underfrequency Response*;
- required to enable the publishing of network constraints identified in *7.1. Advanced Network Planning for a Flexible Future* for resolution; and
- supported by the rollout of *7.6. Shared Market Flexibility*, which will increase the volume of VPP-participating resources eligible to participate in the marketplace and resolve network constraints.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- the number of flexibility service providers enrolled in the marketplace and actively responding to network constraints;
- the ability of participant flexibility service providers to deliver the services procured from them;
    - this would be determined by metering and/or SCADA data;
- the volume of network augmentation avoided through flexibility procurement; and
- the volume of additional CER exports unlocked through co-optimisation of paid and unpaid curtailment.

A wider deployment of the local flexibility marketplace would see:

- eligibility to enrol in the marketplace opened to all customers in South Australia, via energy retailers, VPP operators or CER aggregators;
    - any provider would be able to enrol in any market, subject to technical requirements for participation;
- publishing of *all* suitable distribution network constraints on the platform, and expanding to consider a wider range of transmission constraints as deemed appropriate by ElectraNet;
- market sounding for all RIT-D projects performed through the marketplace; and
- integrating the marketplace with our ADMS DERMS platform to provide a long-term, cyber-secure pathway for all network constraints to be published.

6.4.5 The project aims to drive long term consumer benefits

Establishing a flexibility marketplace for the procurement and dispatch of non-network solutions to resolve constraints across the distribution network will bring significant long-term benefits to all electricity consumers, namely:

- **increased network utilisation** and **avoided network augmentation** via increased demand flexibility and non-network solutions;
    - non-network solutions, including demand flexibility, offer a viable alternative to network augmentation to resolve some constraints. However, the absence of a consolidated marketplace through which these constraints can be published and a response procured, settled and dispatched limits our ability to deploy non-network solutions as general practice;
    - by increasing the accessibility of such solutions, greater volumes of network augmentation can be avoided and existing infrastructure better utilised, delivering unit cost reductions for all customers;
- a **reduction in wholesale energy prices** by way of enabling additional exports from CER;
    - by co-optimising network augmentation with paid and unpaid flexibility, some volume of constraints can be resolved from paid participants, with these constraints otherwise having to be resolved by curtailing CER via a DOE;
    - in the case of export constraints, procuring a paid increase in load or reduction in exports from the flexibility marketplace will result in more network capacity being available for downstream CER to export, in turn offsetting more expensive forms of generation and lowering wholesale energy costs, as per the CECV;
    - the amount of flexibility procured would be optimised based on the CECV that would otherwise be lost if downstream CER export were curtailed.
- **new revenue streams for customers** with CER to access and **further reduce their energy costs**;
    - the flexibility marketplace would facilitate multiple new reward-based demand flexibility markets, including paid response using both active and reactive power, co-optimised as per our *Co-optimising network real and reactive power* pilot, as well as paid services such as that outlined in our *Distributed Emergency Underfrequency Response* pilot;
    - participation in each of these markets would be paid, with payments determined based on the avoided network augmentation costs and/or avoided CER export curtailment costs as per the CECV;
    - these payments would be provided via an energy retailer or VPP operator acting on the customer’s behalf, and portion of the value passed onto the customer via incentive payments.

6.4.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $3.52 million of capex, and $1.55 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to deploy a flexibility marketplace, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.4.4.*

A full cost breakdown, including itemised estimates, is included on the *7.4. Flex Marketplace* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- indicative vendor quotes based on discussions of pilot requirements;
- historical effort to model and tender non-network solutions for RIT-D constraints; and
- delivery of previous reward-based flexibility programs, including our Salisbury VPP and our Energy Masters program.

Efficiencies in delivery have been identified with *7.1. Advanced Network Planning for a Flexible Future, 7.2. Co-optimisation of network real and reactive power and 7.3. Self-Serve Connections Platform Pilot*, as a result of which we have reduced our estimated effort for:

- an uplift of our in-house LV Planning Engine;
- modelling of the efficacy of various non-network solutions in resolving network constraints;
- technical design and industry engagement on an extension of the CSIP-AUS communications protocol;
- an uplift of our core CER management systems for generating, scheduling and dispatching controls from our models through to CER; and
- an uplift of our IEEE2030.5 CSIP-AUS server to handle additional market settlement and dispatch controls, with this server being the public-facing interface through which all CER controls are dispatched and responses received.

6.5 CER market operations interface pilot

This project seeks to increase network utilisation and reduce wholesale energy prices by developing and piloting an operational data sharing interface between SA Power Networks and AEMO. Data shared via this interface would include:

- data from DNSPs to AEMO, primarily:
  - unconstrained and constrained CER export forecasts at the transmission connection point; and
  - available CER curtailment capacity, provided in real-time and considering the expected compliance of each CER device to a given curtailment mechanism;
- data from AEMO to DNSPs, primarily market bids and/or pre-dispatch targets from distribution-connected scheduled generators

6.5.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- more than 30MW of residential solar PV inverters are currently enrolled under a flexible export connection in South Australia, with our Flexible Exports offer currently released to more than 70% of customers in the state. Our Energy Masters pilot will expand this offer to include flexible *import* limits for residential customers, while our Flexible Connections program seeks and offer flexible export and import limits to commercial and industrial customers;
- this growing volume of distribution-connected flexible resources leads to increased uncertainty in the operational forecasts developed by AEMO for market operations. AEMO performs short-term forecasts of system demand over a 5-minute to 8-day time horizon, building a "bottom-up" view of system demand, which in turn sets market prices and the dispatch of scheduled generators in each market interval. Rooftop solar PV is the single largest source of generation in the state and a key determinant of net system demand but is currently assumed to be unconstrained for the purposes of AEMO's operational forecasting;
- in practice, increasing volumes of exports from rooftop PV are being curtailed, whether actively via a DOE, or passively via in-built inverter power-quality response modes such as Volt-VAr, Volt-Watt and overvoltage disconnection. We expect this curtailment to increase as greater volumes of CER connect to the existing distribution network under flexible connections, as well as new energy products coming to the market such as our ARENA *Market Active Solar* trial[26], where energy retailers can curtail exports from rooftop solar during periods of negative wholesale market pricing;
- this increasing divide between AEMO's assumptions in their operational forecasting and the actual curtailment experienced by CER leads to inaccurate demand forecasts, and hence inefficient setting of wholesale market prices and an increased need for ancillary services such as regulation FCAS. AEMO's *Integrating price-responsive resources into the NEM* (IPRR) rule change[27] seeks to develop a market-based solution to this problem, by encouraging distribution-connected CER to participate as a scheduled generator under a DOE;
- our Flexible Exports program today provides DOEs to solar PV, a resource with predictable behaviour, and hence a resource that is simple to generate a DOE for. Large distribution-connected batteries, as well as residential batteries participating in a VPP, however, are unpredictable. Generating a DOE for these resources thus requires a short-term forecast of their behaviour in order to determine to what extent, if any, network limits will be breached, and hence what level of curtailment is required. Once implemented, the IPRR rule change would see the majority of these resources providing bid data to AEMO, which could in turn be passed on to a DNSP to enable DOE generation;

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

27 https://www.aemc.gov.au/rule-changes/integrating-price-responsive-resources-nem

- in addition to an increasing need for AEMO to have visibility over 'day-to-day' curtailment of CER to enhance the accuracy of their operational forecasting, there is a further need to provide AEMO with increased visibility of the available curtailment capacity on the distribution network during a system security event. Currently, where mass-curtailment of distribution connected generators is required by AEMO to maintain system security, an operational demand target is provided to us by AEMO, with responsibility for meeting that target resting on us and AEMO having no visibility of whether that target is achievable, based on the volume of available generation curtailment. Providing AEMO with a 'live' view of available generation curtailment on the distribution network would significantly enhance their ability to manage system security, in the face of increasingly frequency minimum demand events on the system; and
- no technical solution to enabling these new functions exists today, and AEMO has requested that SA Power Networks participate in an exploratory co-design and trial process to understand the most efficient model to integrate CER curtailment into operational forecasting and system operations.

The identified need is therefore to:

- improve AEMO's ability to set efficient wholesale energy prices and the resulting demand for regulation FCAS service by facilitating greater visibility of CER curtailment by DNSPs;
- improve AEMO's ability to manage the security of the energy system during periods dominated by CER generation, by providing live visibility over our ability to curtail CER in the event of a disturbance; and
- improve our ability to efficiently integrate scheduled resources into the distribution network under a flexible connection, by way of receiving short-term market forecasts of these resources from AEMO.

The identified need for this project is pursuant to:

- the capex objective of maintaining the reliability and security of the distribution system through the supply of SCS in clause 6.5.7(3)(iv) of the NER;
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1); and
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.5.2 The project is genuinely innovative

The operation of the distribution network and the operation of the NEM have historically been two distinct roles, with no interface or data sharing arrangements in place between DNSPs and AEMO in their respective operational roles. However, the advent of flexible CER has begun to 'blur the lines' between aspects of the two roles, and is driving a need for regulatory, market-based and technical solutions to ensure efficient operation of the NEM. Reform is progressing across each of these three areas, namely:

- the AEMC is currently exploring regulatory options for clear roles and responsibilities between AEMO and future DSOs as an evolution of the current DNSP role, as part of the delivery of the National CER Roadmap[28];
- market reforms are being concurrently led by the AEMC through the IPRR rule change; and

[28] https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/consumer-energy-resources-working-group/national-cer-roadmap

- AEMO is beginning to explore what technical arrangements may be required for this future via their CER Data Exchange Industry Co-Design ARENA project[29], which SA Power Networks is involved in via the project Expert Working Group. However:
    - the CER Data Exchange project is exploring a wider set of use cases beyond operational forecasting and is currently in a conceptual design phase with no certainty of progression; and
    - AEMO considers that there is a pressing need to pilot an operational forecasting focused interface in the short term, whilst ensuring long-term alignment with wider reforms potentially delivered through the *CER Data Exchange Industry Co-Design* project.

Therefore, this project is genuinely innovative on the basis that:

- no DNSP has to-date developed any operational data sharing arrangements or interface with AEMO;
- AEMO has to-date not yet included CER curtailment in any of their internal operational forecasting processes;
- this pilot would deliver an interface to address an immediate and growing market problem and would inform the future need for national reform in this area; and
- SA Power Networks is best placed to undertake this pilot as AEMO has also directly requested that we participate in an exploratory co-design process to understand the most efficient model to integrate CER curtailment into operational forecasting. AEMO has indicated that this project would form the basis for a wider co-design and implementation process with all DNSPs, with South Australia being the key region for initial testing of concepts.

Further, facilitating efficient connections to the network, in this case enabled by establishing systems to receive short-term forecasts from scheduled resources falls within the scope of our role as a DNSP, and more specifically, within the scope of our SCS and in particular, our 'Common distribution service' as per the AER's Service Classifications.

6.5.3 Alternative funding sources are exhausted

This project is not eligible for DMIAM funding, but may be eligible for co-funding through pursuing an ARENA grant, as:

- the project does not directly align to the DMIAM's scope as it does not concern demand management or the modification of the drivers of network demand, but instead focuses on delivering wider system benefits by way of improving the accuracy of AEMO's operational forecasting and the resultant efficiency of wholesale energy pricing, as well as improving network utilisation through enhancing our ability to generate DOEs for batteries; and
- whilst the nature of the pilot does not directly align with ARENA's current funding priorities with regard to flexible demand, in this case not being a demand flexibility product, but rather a way to enhance our ability to offer flexible connections to large batteries, we would nonetheless seek to explore and exhaust potential ARENA co-funding for this project prior to fully funding it via the Innovation Fund.

[29] https://arena.gov.au/projects/aemo-cer-data-exchange-industry-co-design/

6.5.4 The project is prudently scaled

Implementation risks being addressed

This project covers significant changes to core elements of the operation of the energy system, for which extensive testing and solution exploration is required before any wider-scale deployment is performed. The specific implementation risks being addressed via this pilot are:

- AEMO's operational forecasting process underpins the dispatch of scheduled generators in the NEM, and the determination of wholesale energy pricing in each market interval. Integrating CER curtailment forecasts into AEMO's processes could result in further inefficiencies in wholesale prices, were those CER curtailment forecasts to be inaccurate. Significant testing as to the suitability of DNSPs CER curtailment forecasts is hence needed before a 'production' implementation of this concept could be deployed;
- the allocation of network capacity to a scheduled battery operating under a DOE, if not done efficiently, could result in further inefficiencies driven in AEMO's determination of wholesale energy pricing, by way of excessively limiting the bids placed by those batteries, and in turn restricting their ability to set or lower market pricing. The efficiency of a DOE produced using scheduled battery bids as input will require extensive testing and exploration before a 'production' implementation of this concept could be deployed; and
- the ability to curtail CER in an emergency minimum-demand event is becoming an increasingly critical part of AEMO's 'toolkit' in managing a stable power system. Should the 'live' view of available generation curtailment capacity provided to AEMO by a DNSP be inaccurate, AEMO may not enact other emergency mechanisms available to them, instead relying on DNSPs to meet an unattainable curtailment target, potentially resulting in a system black event. The accuracy of a DNSPs forecasts of available generation curtailment capacity will require high confidence before a 'production' implementation of this concept could be deployed.

Deciding on project scale

Piloting the CER market operations interface will allow us to explore the implementation risk without compromising AEMO's ability to operate a secure power system. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout of a more developed interface across the NEM by AEMO.

Specifically, the scope of the pilot would be limited to:

- calculating CER curtailment forecasts and available generation curtailment capacity in our corporate IT environment, and not integrated into our Advanced Distribution Management System (ADMS) Distributed Energy Resources Management System (DERMS), avoiding the need for a further uplift of that product; and
- ingestion of bid data only from a subset of 10 scheduled resources on our network, and subsequent DOE provision to those resources.

This project is appropriately scaled as the inclusion of 10 scheduled resources will allow for suitable diversity in the types of resources that we receive forecasts from, with the method through which these forecasts are integrated into DOE generation processes varying between resource types.

We are not proposing to limit the portions of the network included in the calculated CER curtailment forecasts or available generation curtailment capacity, as AEMO's operational dispatch model considers only a single datapoint for the South Australian energy system. Provision of any data that does not consider all resources in the state would thus not address AEMO's need for accurate consideration of state-wide curtailment forecasts to produce more efficient wholesale pricing.

This project would run over a period of 2 years, beginning in Q4 2025. Development of an operational forecasting interface between DNSPs and AEMO is supportive of the efforts to increase network utilisation by accelerating adoption of flexible connections via *7.1. Advanced Network Planning for a Flexible Future, 7.3. Self-Serve Connections Platform* and *7.4. Local Flexibility Marketplace*, enabling more efficient DOE generation for scheduled resources participating in these pilots, and integrating the outcomes of the flexibility these pilots enable into AEMO's operational forecasting.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- analysis from AEMO on the quantified impacts of sharing CER curtailment data on operational forecasting accuracy, and the resulting impact on wholesale energy prices and regulation FCAS requirements;
- user feedback from AEMO's system operations team on the format and frequency of the available generation curtailment data; and
- experience of the 10 scheduled resources providing bid data to us, and the resulting service levels they experience under their flexible connection.

Transitioning this pilot to a BAU implementation will largely be driven by AEMO's desire to roll-out data-sharing requirements to all DNSPs, and that the exact nature of the long-term technical solution for the data-sharing interface will depend on the capabilities across all DNSPs. A more fulsome implementation would require a further uplift to our ADMS DERMS platform, to shift the calculation of CER curtailment forecasts and available generation curtailment capacity into this operational and cyber secure environment.

6.5.5 The project aims to drive long term consumer benefits

Development of a pilot data-sharing interface for CER curtailment and scheduled generator forecasts will drive significant long-term benefits to all electricity consumers, including:

- **Increased network utilisation** and **avoided network augmentation** via more **optimal capacity allocation** to scheduled generators:
  - the absence of short-term behavioural forecasts from batteries and other unpredictable resources makes it difficult to generate efficient DOEs for these resources, with DNSPs today having to apply conservative assumptions resulting in sub-optimal allocation of network capacity, and in-turn an under-utilisation of the surrounding network;
  - by integrating market bids from scheduled generators into our DOE calculation systems, we can provide more optimal capacity allocation to those generators and allow a greater volume of flexible resources to connect to our existing network under flexible connections, driving up network utilisation and reducing network unit costs for all customers;
- **more efficient wholesale energy pricing** and **reduced requirements for regulation FCAS** via more accurate operational forecasting:
  - integrating forecasts of CER curtailment into AEMO's operational forecasting process will directly address current inaccuracies in their forecasts, and in turn inefficiencies in the result wholesale market pricing and FCAS requirements in each market interval; and
- **improved system security** via greater visibility of available generation curtailment capacity:
  - by providing AEMO with a 'live' view of the available generation curtailment capacity on the distribution network, their system operators will have increased certainty on the ability of a DNSP to maintain operational demand above a given target in a minimum demand event; and

- this will ensure that informed decisions can be made by AEMO regarding the need to potentially enact other emergency mechanisms such as market intervention, should the DNSP not have sufficient curtailment capacity available to manage a contingency.

6.5.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $2.62 million of capex, and $0.35 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to implement a market operations interface between ourselves and AEMO, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.5.4.*

A full cost breakdown, including itemised estimates, is included on the *7.5. Market Interface* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- the effort to develop our in-house Flexible Exports Constraints Engine, a tool which performs short-term forecasts of curtailment requirements on the LV network and generates export limits;
- the effort to develop our in-house LV Planning Engine; and
- the costs to deploy our ADMS DERMS trial.

Efficiencies in delivery have been identified with *7.8. Distributed Emergency Underfrequency Response,* as a result of which we have reduced our estimated effort for an uplift of our DER Database to support the collection and management of data relating to compliance of CER to various curtailment mechanisms.

6.6 Shared market flexibility pilot

This project seeks to increase network utilisation and reduce wholesale energy prices by piloting shared communications infrastructure between a DNSP and a VPP operator, and would seek to deliver:

- an uplift of our CSIP-AUS systems to handle additional control signals required by VPP operators; and
- a field trial with 2 VPP operators, each with 100 participating customers.

6.6.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- South Australia currently has 18 operational VPPs, with more than 30% of residential customers with a battery system choosing to participate in the NEM via one of these VPPs. The number of VPPs operating in South Australia, and the volume of customers participating in them, are the highest in the NEM;
- current VPP offerings, provided by energy retailers or CER aggregators currently impose restrictions on a customer's ability to participate in their offer based on the make and model of their CER. These restrictions are in place due to the limited number of integrations between a given retailer or aggregator and the various CER devices on the market, ultimately driven by a lack of interoperability between VPP operators and CER. Developing an integration between a given VPP and a new CER model requires several factors, namely:
  - a commercial relationship between the VPP operator and the CER OEM, noting that several VPPs are operated by these OEMs, leading to commercial tensions for third-party VPP operators seeking to integrate with their devices; and
  - technical integrations between the chosen control platform of the VPP operator and each make/model of CER that they are aiming to control;
- where a commercial arrangement can be established between a VPP operator and a CER OEM, developing these integrations can be time-consuming and costly for the VPP operator, typically requiring significant engineering work to integrate with the unique implementation of various communications protocols deployed by CER OEMs. This leads to a reduction in the portion of VPP revenue that is available to be passed on to participating customers, as the VPP operator has higher engineering costs to recoup; and
- these issues exist today primarily for residential battery systems, as the main end-device target for a VPP operator. However, we expect that in future, VPPs will expand to offer 'whole-of-home' participation, utilising all CER within the home that a customer is willing to opt-in to market participation. A continued lack of interoperability between VPP operators and CER will restrict mass participation in whole-of-home VPPs, limiting both potential network and market benefits as well as customer choice.

The identified need for this project is thus to improve network utilisation and reduce wholesale energy costs by introducing interoperability between CER and the market for the purposes of orchestration, utilising existing DNSP communications infrastructure to provide a low-cost path for VPP operators to deliver services to the network and the market.

The identified need for this project is pursuant to:

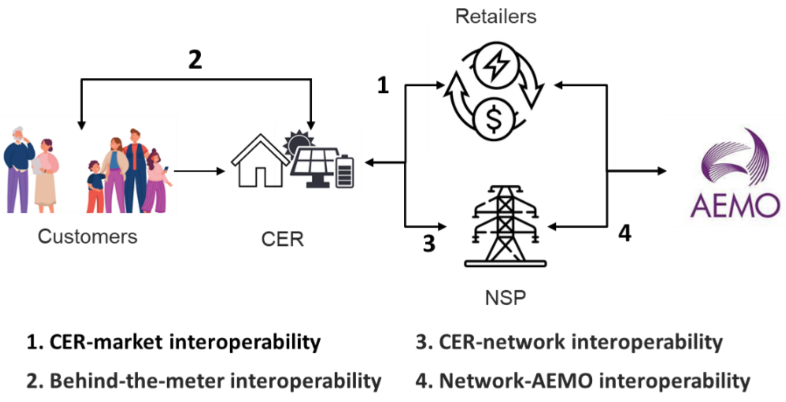
- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1);
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and

- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.6.2 The project is genuinely innovative

Interoperability is in place today for parts of the energy system, but significant progress is still required to realise a full suite of customer benefits. *Figure 11* provides an overview of the interoperability domains in the NEM, as identified by the Energy Security Board in their *Interoperability Directions Paper* in 2022[30].

Figure 11 - the Energy Security Board's interoperability domains



Interoperability efforts to date have largely focused on Domain 3, CER-network interoperability. SA Power Networks has been a national leader in this area, having pioneered the development of the Common Smart Inverter Protocol – Australia, or **CSIP-AUS**. This is an implementation of the IEEE 2030.5 standard co-developed by SA Power Networks and an industry working group through our *Flexible Exports for Solar PV* ARENA pilot in 2021. CSIP-AUS enables interoperable communications between a DNSP and CER, with requirements for this capability currently legislated in both South Australia and Victoria and expected to become a national requirement through the delivery of Priority T1 in the National CER Roadmap.

CSIP-AUS is a key element of energy system interoperability, but today is only used for communications between a DNSP and CER, primarily for the purposes of flexible export limits and emergency backstop mechanisms. Our *Market Active Solar* ARENA trial seeks to expand the use of CSIP-AUS to enable interoperability for Domain 1, CER – market, by using SA Power Networks' CSIP-AUS systems to establish communications between retailers and CER to curtail PV exports during periods of negative wholesale pricing.

We consider that CSIP-AUS can be leveraged further for CER-market interoperability, by expanding the model trialled in *Market Active Solar* to one where a full suite of VPP controls are passed through a shared DNSP & retailer CSIP-AUS pathway to CER. This presents an efficient, interoperable way to enable VPP participation at scale, removing commercial and integration barriers to the provision of VPP services to all new CER, regardless of make or model.

Thus, this project proposes to explore the viability of interoperable VPP operation by way of shared CSIP-AUS communications infrastructure between a DNSP and a retailer or aggregator, and would seek to deliver:

- an uplift of our CSIP-AUS systems to handle additional control signals required by VPP operators; and
- a field trial with 2 VPP operators, each with 100 participating customers.

[30] https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand#development-of-interoperability-policy

This pilot is considered truly innovative on the basis that:

- it will be the first demonstration of VPPs leveraging a standards-based communications protocol (like CSIP-AUS) to integrate with a broad set of CER devices. VPPs to-date have consisted of a small number of bespoke integrations with a small number of equipment vendors using proprietary communications, severely limiting the potential pool of customers;
- it will be the first demonstration of VPPs leveraging a DNSP's digital infrastructure to gain fast access to communications with a large number of equipment types (and therefore customers). This builds upon the work in the *Market Active Solar Trial* which will demonstrate retailers leveraging similar digital infrastructure for the much simpler task of solar management; and
- it will be the first demonstration of VPP control mechanisms using the CSIP-AUS protocol, which opens the door for customer equipment to be truly interoperable between different retailer products.

SA Power Networks is best placed to undertake this pilot as it will build directly on existing work undertaken through our *Market Active Solar* trial, leveraging our CSIP-AUS infrastructure developed for our Flexible Exports program. We are the only DNSP with a scaled, production implementation of this infrastructure, meaning that only a marginal uplift is required to enable this full shared communications pathway.

6.6.3 Alternative funding sources are exhausted

This project is not eligible for DMIAM funding, but may be eligible for ARENA co-funding, as:

- the project does not directly concern demand management or the modification of the drivers of network demand, but instead focuses on enabling a greater volume of resources to participate in the energy market by way of a VPP, mitigating demand only to the extent that wholesale market operations correlate with network demand; and
- our ability to seek co-funding from ARENA will likely be dependent on the outcomes of our current Market Active Solar project, and ARENA's willingness to co-fund a larger direct continuation of that project.

6.6.4 The project is prudently scaled

Implementation risks being addressed

This project underpins the core operations of VPPs, a resource which we estimate to make up approximately 24MW of the current generation capacity in South Australia. While transitioning to a shared communications pathway between DNSPs and VPP operators poses significant benefits, the transition requires exploration of key risks before being implemented as an at-scale replacement for current VPP control pathways, including:

- conflicts between DOE controls and VPP controls sent via the shared communications pathway, potentially resulting in non-conformance to a DOE and hence breaches of network capacity causing an outage; and
- non-conformance to market bids from scheduled VPPs due to issues in the shared communications pathway, leading to inaccurate demand forecast from AEMO and in-turn inefficient wholesale market pricing and increased regulation FCAS costs;

Deciding on project scale

Piloting a fully interoperable, shared communications pathway between DNSPs and VPP operators will allow us to explore the implementation risks without compromising the ability of VPP operators to manage their VPP within the limits of the distribution network and the market. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout of a more developed interface to all VPP operators in South Australia.

Specifically, the scope of the pilot would be limited to:

- deploying the shared communications pathway to two VPP operators, comprising 100 enrolled customers each; and
- the existing control interfaces from each VPP operator would be maintained in parallel the pilot interface, ensuring that the VPP can still operate as intended in a failsafe scenario.

This project is appropriately scaled on the basis that:

- including two VPP operators in the pilot will allow for us to test the shared communications pathway with two different endpoints, with each VPP operator utilising a different control platform;
- this will ensure that the systems are fit for purpose for all VPP operators and truly interoperable, not bespoke for a single party; and
- in addition, the inclusion of 100 participating customers will allow for the pilot to include a variety of customer and CER types, testing the proposed technical solution with a variety of CER devices and the proposed VPP offers with a variety of customer demographics.

This pilot would run over a 1.5 year time period, beginning in Q3 2026. Developing a shared communications between VPP operators and DNSPs will support the implementation of both *7.4. Local Flexibility Marketplace* and *7.8. Distributed Emergency Underfrequency Response,* by way of reducing the barriers to VPP participation and in-turn increase the volume of VPP-participating resources eligible to resolve network constraints via the marketplace, and participate in emergency underfrequency response.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- the ability of the two partner VPP operators to:
    - expand their VPP offering to new makes and models not previously available through their existing control platform;
    - fully replicate their existing market operations via the shared pilot interface;
- quantified cost reductions for the VPP operators; and
- our ability to ensure that the VPP resources continue to conform to our DOE signals when dispatched using the shared pilot interface.

A wider deployment of the shared communications interface would see us expand the partnership to all VPP operators in South Australia, providing them an option to remove their reliance on their existing control platforms and establish fully interoperable links to all new CER in the state. We expect this model could be replicated by other DNSPs as they deploy CSIP-AUS infrastructure to enable flexible exports and emergency backstop mechanisms, allowing for full national interoperability of VPPs and DOEs with CER.

6.6.5 The project aims to drive long term consumer benefits

Leveraging DNSP communications infrastructure to develop a shared market flexibility platform will enable interoperability between a retailer, aggregator or VPP operator and CER, driving significant long-term benefits to all electricity consumers, including:

- **increased network utilisation** and **avoided network augmentation**, driven by greater VPP uptake:
    - establishing interoperability between VPP operators and CER will open up VPP eligibility to all CER, instead of a select few, allowing any customer with any make or model of CER to participate;

    - interoperability will also reduce the operating costs of VPPs, by way of removing the need for the development and maintenance of bespoke integrations between each VPPs control platform and each make and model of CER;
        - lower costs to operate a VPP will lead to a greater share of market revenue available to pass on to customers;
    - these two factors will lead to more open and financially attractive VPP offers, in turn driving further uptake and providing more opportunities for VPPs to support the network, participating in demand flexibility programs to increase network utilisation and avoid augmentation;
- **reduced wholesale energy pricing**, driven by greater VPP uptake:
    - increased VPP participation will lead to a lower reliance on current scheduled generators, including costly peaking gas plants or interstate imports, reducing wholesale energy pricing and avoiding the need to build further large-scale generation; and
    - we note that the IPRR rule change will likely lead to a significant number of VPPs becoming scheduled generators, allowing them to set the market spot price. Given VPPs can typically provide energy at a far lower cost than most other generators, this will lead to a further long-term reduction in wholesale energy pricing.
- **expanded CER revenue streams** and **reduced upfront CER upfront costs**, via expanded VPP driving lower cost to entry for VPPs
    - we expect that the value passed onto participating customers by VPP operators will increase via interoperability reducing the operating costs of a VPP, and that this will typically be passed on either as a reduction to the upfront CER costs or as an ongoing incentive payment.
    - participating customers will have the added benefit of being able to swap their fully interoperable equipment between different VPP products, providing greater choice in offers and fostering greater competition in the market.

6.6.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $1.24 million of capex, and $0.13 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to implement systems and processes for shared flexibility infrastructure between DNSPs and market participants, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.6.4.*

A full cost breakdown, including itemised estimates, is included on the *7.6. Shared Flexibility* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* These costs have been estimated based on the effort to deliver our Market Active solar project, including:

- the development of an API to receive solar curtailment controls from energy retailers;
- uplifts of our CER management systems to pass those curtailment signals onto CER via CSIP-AUS; and
- industry engagement on the proposed model.

Efficiencies in delivery have been identified with *7.2. Co-optimising network real and reactive power* and *7.4. Local Flexibility Marketplace Pilot,* as a result of which we have reduced our estimated effort for:

- an uplift of our core CER management systems for generating, scheduling and dispatching controls from our models through to CER; and
- an uplift of our IEEE2030.5 CSIP-AUS server to handle additional VPP controls, with this server being the public-facing interface through which all CER controls are dispatched and responses received.

6.7 Integrating DOEs and system services pilot

This project seeks to enhance system security by integrating DOE calculation processes with CER market enrolment to provide greater network capacity to CER providing essential system services such as FCAS.

We will work with two CER OEM partners to uplift both our systems and their devices to receive two DOEs:

- one DOE for normal system operation; and
- one DOE for essential system services provision.

CER participating in essential system services would be given priority network access, recognising the critical role these resources would play in supporting a reliable, stable power system.

6.7.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- costs across the 10 FCAS markets in the NEM totalled $135M in 2023, with increasing volumes of this service being provided by CER;
- to best integrate all CER into the local distribution network, they must operate under a flexible connection, enabled by the provision of a DOE;
- therefore, there is an emerging risk that CER will be limited in providing these services by local network constraints, meaning that they will instead need to be provided by more expensive, centralised sources. There will be an increased need for FCAS provision from CER in coming years as significant volumes of traditional FCAS sources exist the NEM, primarily fossil fuelled generation; and
- DOEs are calculated based on the normal rating of a network asset, intended to protect the network from overload. Our low-voltage transformers can be loaded above their rating for short-periods of time without causing an outage, however, instead only impacting the lifespan of that asset. Co-optimisation is required to understand the ideal level of overload, in order to maximise the market benefits of increased low-cost FCAS provision without driving greater levels of investment in network asset replacement due to increased aging.

The identified need for this project is thus to increase system security by enabling greater provision of FCAS and other essential system services from distributed CER, mitigating the risk imposed by exiting thermal generation in the NEM and lowering the costs of maintaining a stable power system.

The identified need for this project is pursuant to:

- the capex objective of maintaining the reliability and security of the distribution system, through the supply of SCS in clause 6.5.7(3)(iv) of the NER;
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.7.2 The project is genuinely innovative

Optimising the interaction between the operation of CER under a DOE and the provision of system services such as FCAS from CER is an approach that is as yet untested within the NEM. Distributed provision of FCAS from CER occurs today but is not well-integrated into the operation of the distribution network, with no visibility from a DNSP over the market services provided by a VPP.

This project would seek to recognise the critical role that these resources are playing and the cost reductions that they can provide by:

- registering their provision of system services within our network systems;
- generating two DOEs for these resources:
  - one applied when the resource is operating normally, acting on behalf of the customer or participating in the wholesale energy market;
  - one applied only when the resource is operating in response to the FCAS market;
- the secondary DOE would allow them to export or import up to the *emergency* rating of our network assets, in contrast to the normal asset rating applied to the primary DOE; and
- these resources would be prioritised in the process of mediating network capacity performed whilst generating DOEs, ensuring that FCAS provision is not limited in favour of providing non-market active resources with greater export capacity.

This project would build on work undertaken as part of our *Advanced VPP Grid Integration* trial[31], our 2019 ARENA project that aimed to understand the potential of a VPP to participate in wholesale energy markets under a DOE, as well as AEMO's *VPP Demonstrations*[32], which explore the potential for VPPs to participate in the FCAS markets.

This pilot is considered genuinely innovative as:

- no activity has yet explored the potential of providing priority network access via DOEs to resources providing essential system services;
- no activity has developed systems to generate and dispatch two unique CSIP-AUS based DOEs to CER; and
- no activity has attempted to optimise the loading of network assets to their emergency ratings, and the resultant acceleration in asset aging, with the benefits provided to the wider energy system from increased provision of FCAS, or any other service, from low-cost and distributed sources.

SA Power Networks is best placed to undertake this pilot as it directly builds upon our production systems to generate and dispatch DOEs to CER, a capability not currently deployed at scale by any other DNSP. Additionally, South Australia has the highest VPP participation rates in the NEM, maximising the potential number of CER devices available to participate in the pilot by providing FCAS services via a VPP.

6.7.3 Alternative funding sources are exhausted

This project is not eligible for DMIAM funding, but may be eligible for ARENA co-funding, as:

- the project does not directly concern demand management or the modification of the drivers of network demand, but instead focuses on increasing the potential for CER to provide essential system services and contribute to a stable power system by allocating greater network capacity to these resources; and
- the nature of the pilot does not directly align with ARENA's current funding priorities with regard to flexible demand, in this case not being a direct demand flexibility product, but rather a means to optimise the provision of essential system services for CER already participating in demand flexibility by way of receiving a DOE. However, we would seek to explore and exhaust potential ARENA co-funding for this project prior to fully funding it via the Innovation Fund.

[31] https://arena.gov.au/projects/advanced-vpp-grid-integration/
[32] https://arena.gov.au/projects/aemo-virtual-power-plant-demonstrations/

6.7.4 The project is prudently scaled

Implementation risks being addressed

This project seeks to directly alter the allocation of network capacity under a DOE, a process designed to ensure that the operational limits of the network are not breached from CER activity. Whilst significant benefits can be realised through providing additional network access to CER participating in essential system services, doing so introduces several new risks which this pilot will address, including:

- emergency network asset ratings used to generate secondary DOEs leading to a continued overload and a subsequent asset failure; and
- priority mediation of network capacity provided to FCAS-participating CER leading to significant constraints on other CER.

Deciding on project scale

Undertaking a pilot of DOE calculations integrated with system services will allow us to explore the potential of this concept to support system security whilst managing the risks of potential network overloads. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout of a more developed process to all CER in South Australia

The scope of the pilot would be limited to:

- partnering with two CER OEMs; and
- deploying the secondary DOEs to 50 devices per OEM, for a total of 100 devices included in the trial.

This project is appropriately scaled as including two CER OEMs in the pilot will allow for us to test the revised allocation of network capacity to a diverse set of CER devices, ensuring that the secondary DOE can be deployed in an interoperable manner suitable for any future CER device to respond to.

Additionally, the inclusion of 100 participating customers will allow for the pilot to test the proposed solution across:

- a diverse base of customers, with variations in behind-the-meter load behaviour potentially impacting the utilisation of the secondary DOE; and
- a diverse set of network assets, including assets of varying age, condition and location;
    - this will inform the results of our proposed co-optimisation of network loading and ensure that it is fit-for-purpose across the entire network.

This pilot would run over a 2-year time period, beginning in Q1 2027. Developing systems to enable greater provision of essential system services under a DOE is:

- a service to be integrated with the *7.4. Local Flexibility Marketplace*, this marketplace being the platform through which enrolment in the secondary DOE could be managed; and
- supports the deployment of *7.8. Distributed Emergency Underfrequency Response*, enabling a greater volume of CER to participate in the provision of FCAS services and hence have their site metering and device response uplifted to a level more suitable for the further provision of emergency underfrequency response in that pilot.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- the ability of OEM partners CER to receive and apply two DOEs;
- our ability to ensure that the FCAS resources conform to our secondary DOE when providing FCAS response, and to our primary DOE at all other times;
- quantified increases in the volume of FCAS response procured from CER in South Australia; and
- quantified increases in access to FCAS revenue for a VPP operator, and an analysis of how that could increase the incentivises provided to customers.

A wider deployment of this service would see us expand the partnership to all CER in South Australia, allowing a VPP operator to register their essential service participation with our systems and have their CER receive a secondary DOE accordingly. A complete integration of this process into our ADMS DERMS would be undertaken, allowing for full optimisation of network capacity between resources providing system services and the loading of the network at all levels.

6.7.5 The project aims to drive long term consumer benefits

Developing systems to calculate and dispatch secondary DOEs with greater allocation of network capacity to resources providing essential system services will bring long-term benefits to all energy consumers through:

- **reduced wholesale energy pricing** and **reduced energy system emissions (increased value of emissions reduction),** enabled via reduced reliance on centralised generation for FCAS provision;
  - the costs of providing FCAS are recovered from all customers, with these costs making up an increasing portion of wholesale energy costs in recent years. Large synchronous generators have historically been the primary source of FCAS, but these generators are typically fossil-fuelled and carry high generation costs;
  - enabling greater volumes of FCAS provision from CER will reduce reliance on other FCAS sources, with CER able to provide these services at a lower cost and with lower emissions factors, in turn reducing the wholesale costs of energy for all customers and increasing the value of emissions reduction for all consumers.
- **improve system security** via greater & distributed FCAS provision;
  - removing barriers to providing FCAS and other system services from CER will increase the overall volume of resources providing these services, with lower upfront & operating costs for a VPP to establish FCAS capabilities than to establish new sources of thermal generation;
  - an overall increase in the number of resources providing FCAS, coupled with the geographic diversity of CER providing these services will lead to an increase in system security, with a distributed VPP being more cost-effective and less subject to outages than a centralised generator;
- **increased network utilisation** by allowing import and export up to emergency network ratings of low-voltage transformers;
  - CER providing FCAS would be modelled with unique parameters in our DOE generation systems, allowing them to utilise network capacity up the emergency ratings of our LV transformers, whilst other CER would be limited to the normal LV transformer rating;
  - the utilisation of these emergency ratings would be calculated such that the benefits of increased FCAS provision from CER are optimised against the accelerated aging of our assets through increased loading, ensuring that optimal utilisation of the network can be delivered whilst contributing to wider system security;
- **expanded CER revenue streams** via increased VPP FCAS revenue;

- the provision of FCAS currently represents a significant amount of revenue for most VPPs[33], with a portion of this revenue passed onto customers as an enrolment incentive;
- by unlocking greater network capacity for CER providing FCAS, and in-turn enabling these resources to have greater access to those markets, the VPP operator will increase their market revenue and be able to reflect that increase in their customer incentive payments.

6.7.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $1.31 million of capex, and $0.10 million of opex.

These estimates are reasonable, having largely been based on our actual costs incurred to deliver projects of a similar nature in past. They reflect only the costs to establish a pilot capability to integrate CER providing essential system services under a DOE, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.7.4.*

A full cost breakdown, including itemised estimates, is included on the *7.7. DOE System Services* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- the costs to implement our ADMS DERMS trial; and
- the effort to develop our Flexible Exports Constraints Engine.

Efficiencies in delivery have been identified with *7.2. Co-optimisation of network real and reactive power, 7.3. Self-Serve Connections Platform, 7.4. Local Flexibility Marketplace* and *7.6. Shared Market Flexibility,* as a result of which we have reduced our estimated effort for:

- an uplift of our core CER management systems for generating, scheduling and dispatching controls from our models through to CER, in this case to generate new secondary DOE controls;
- an uplift of our IEEE2030.5 CSIP-AUS server to handle secondary DOE controls, with this server being the public-facing interface through which all CER controls are dispatched and responses received; and
- network model tuning and maintenance.

[33] https://aemo.com.au/-/media/files/initiatives/der/2021/vpp-demonstrations-knowledge-sharing-report-3.pdf

6.8 Distributed emergency underfrequency response pilot

This pilot seeks to improve system security by developing systems to procure distributed underfrequency response from CER. This capability would be integrated with the *Local Flexibility Marketplace* pilot, with a trial group of participating customers paid via a VPP partner for commissioning, availability, and dispatch.

In a system security event, underfrequency response would first be sought from CER, given the opt-in, paid nature of this response, before any feeder load shedding was enacted.

6.8.1 The identified need

This project responds to the following context:

- electrification poses an increase to peak demand, both at the local network level and the wider system level;
- where network capacity is insufficient to meet peak demand, the risk is managed by the enactment of either automated underfrequency load shedding or manual rotational load shedding, both at the feeder level;
- feeder load shedding is a ‘blunt’ measure to manage demand, impacting all customers on a given feeder and necessarily reducing demand by more than is actually required;
- increasing volumes of CER and commercial & industrial loads are enrolled in flexible connections, connected to DNSP systems with the ability to remotely curtail their load or generation;
- this presents an opportunity to better manage periods of peak demand with targeted shedding of loads with minimal impact to customer amenity;
- further, an immediate shortfall in emergency underfrequency response capacity for South Australia has been identified by AEMO in the 2020 Power System Frequency Risk Review,[34] requiring urgent action to mitigate the risk of insufficient underfrequency response.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER;
- the capex objective of maintaining the reliability or security of the distribution system through the supply of SCS, in clause 6.5.7(3)(iv) of the NER;
- the capex objective of meeting or managing the expected demand for SCS in NER clause 6.5.7(1);
- the capex criteria of achieving the most cost-efficient solutions by which to meet the capex objectives, in clause 6.5.7(c)(1)(a) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

6.8.2 The project is genuinely innovative

Load shedding is an established mechanism for managing peak demand in the NEM, enacted by all DNSPs via manual rotational load shedding or automated underfrequency load shedding delivered locally by feeder protection relays. SA Power Networks has recently completed a major upgrade of our underfrequency protection systems, by implementing directional underfrequency feeder load shedding capabilities, ensuring that in an underfrequency event, no feeders that are acting as a net generator are disconnected, which would otherwise result in a further loss of generation and a worsening of the underfrequency issue.

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[34] 2020 PSFRR Stage 2 Final Report (aemo.com.au)

However, we consider that no distribution network to date has enacted distributed, reward-based underfrequency load shedding, procuring services from CER to ensure the minimal amount of resources are curtailed to maintain a stable system frequency.

This project would seek to:

- develop models to calculate the required volume of underfrequency in order to maintain system frequency;
- integrate these new underfrequency calculation models into our *Local Flexibility Marketplace*, through which enrolment in the provision of distributed emergency underfrequency response could be managed, including commissioning of underfrequency controls, ongoing availability and dispatch; and
- engage with the CER industry to uplift their systems to receive new emergency underfrequency controls, and co-develop efficient offers for VPP operators, energy retailers and CER aggregators to participate in this new service.

SA Power Networks is best placed to undertake this pilot due to our world-leading volumes of CER participating in a VPP, with underfrequency services requiring a VPP through which enrolment and dispatch could be managed. Additionally, our established production systems for DOE calculation and dispatch will be leveraged to provide underfrequency controls to CER, with these systems not currently operational for any other DNSP. This project involves activities that fit within the scope of our role as a DNSP, and more specifically, within the scope of our SCSs and in particular, our 'Common distribution service' as per the AER's Service Classifications.

6.8.3 Alternative funding sources are exhausted

This project is unlikely to be eligible for co-funding, whether via the DMIAM or an ARENA grant, as:

- the project does not directly concern demand management or the modification of the drivers of network demand, but instead focuses on minimising the need to enact feeder load shedding in order to mitigate peak demand risk, and on a system security issue; and
- the nature of the pilot does not align with ARENA's current funding priorities with regard to flexible demand, in this case not being a direct demand flexibility initiative, but rather a means to utilise the inherent flexibility of new loads for the purposes of enhancing system security and reducing the risk of load shedding for other customers.

6.8.4 The project is prudently scaled

Implementation risks being addressed

This project seeks to directly alter the mechanism through which emergency underfrequency load shedding is enacted, a critical tool in managing system security. Whilst significant benefits can be realised through enabling the provision of emergency underfrequency load shedding from distributed resources, doing so introduces several new risks which this pilot will address, including:

- inability of inverter-based resources to provide accurate or sufficient underfrequency response, leading to a continuation of underfrequency conditions and outages for more customers; and
- a lack of interoperability between CER, where multiple devices are located on a single site.

Deciding on project scale

Piloting the procurement of emergency underfrequency response from distributed CER will allow us to support system security and reduce the risk of load shedding to consumers, whilst managing the risks of potential insufficient underfrequency response. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout of a more developed process to all CER in South Australia.

The scope of the pilot would be limited to:

- partnering with two CER OEMs or aggregators, uplifting their systems to receive and apply new underfrequency controls; and
- piloting the procurement of underfrequency response from 100 customers across those two partners.

This project would run over a two year time period, beginning in quarter 4 2025. There is an existing, urgent gap for underfrequency response in South Australia, as identified by AEMO in the 2020 Power System Frequency Risk Review.

Developing systems to procure underfrequency response from CER is:

- an input into *7.4. Local Flexibility Marketplace,* with participation in and payments for the proposed underfrequency response services managed through the marketplace; and
- supported by the deployment of shared DNSP and VPP operator communications pathways through *7.6. Shared Market Flexibility*, increasing the ability of VPP operators to enrol CER in flexibility service provision.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- the ability of our network models to calculate distributed underfrequency requirements, and the volume of response required from individual CER devices;
- sufficient market participation from VPP operators, such that enough distributed underfrequency response is available to resolve real-world underfrequency constraints;
- quantified reductions in the volume of energy unserved by our network due to feeder load-shedding, noting that this may be simulated for the purposes of the pilot;
- quantified increases in revenue for a VPP operator due to the new underfrequency payments from DNSPs, and an analysis of how that could increase the incentives provided to customers.

A wider deployment of this service would see us expand the offer to all CER in South Australia, allowing a VPP operator to register their controlled CER with us via the *Local Flexibility Marketplace*, completing a commissioning process before being eligible for ongoing availability and dispatch payments. As the volume of participating resources and our confidence in CER's ability to reliably provide underfrequency response increases, our reliance on feeder-load shedding would be reduced.

6.8.5 The project aims to drive long term consumer benefits

Establishing systems to calculate, enrol, procure and dispatch emergency underfrequency response from CER as an alternative to rotational load shedding will bring long-term benefits to customers, namely:

- **improved system security** via greater availability of underfrequency response;
    - feeder load shedding is a 'last resort' approach to managing underfrequency, only performed when all other avenues have been exhausted. On the contrary, procuring underfrequency response from CER could be enacted much earlier, due to the minimal customer impacts and the payment arrangements that would be in place;
    - having access to an earlier, more 'targeted' underfrequency management tool would increase AEMO's ability to maintain a secure power system;

- **improved customer experience** due to a reduction in reliance on feeder load shedding;
    - the provision of distributed underfrequency load shedding from customers who have opted in to providing such a service will ensure that the impact to customer amenity is minimised, with the probability of a non-participating customer to be impacted by load shedding greatly reduced;
- **new revenue streams for customers** with CER to access and **further reduce their energy costs;**
    - by way of the provision of underfrequency response being an opt-in, paid service provided by customer via a VPP operator, CER aggregator or energy retailer, payments from a network provided to these third-parties can be passed on to participating customers.

6.8.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $1.07 million of capex, and $0.69 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to plan a flexible network, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 6.8.4.*

A full cost breakdown, including itemised estimates, is included on the *7.8. Distributed Underfrequency* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* Given the complex nature of the work involved, we do not have firm vendor or consultant quotes for elements involving external support. These costs have been estimated based on:

- effort to develop our Flexible Exports Constraints Engine;
- effort to develop our existing DER Database; and
- tender responses received through our 2022 Emergency Underfrequency Response call for tenders[35].

Efficiencies in delivery have been identified with *7.5. CER market operations interface,* as a result of which we have reduced our estimated effort for an uplift of our DER Database to support the collection and management of data relating to the underfrequency response capacity and time of CER, the aggregator or VPP operator through which they are enrolled and the status of the device to respond to underfrequency events.

[35] Tenders - SA Power Networks

7 Theme 2: Community Resilience

7.1 Emergency services data sharing pilot

This project seeks to establish a data-sharing interface between SA Power Networks and emergency services in South Australia, with the aim of enhancing the state's coordinated approach to emergency management by way of providing real-time information to these parties on:

- the state of our network;
- safety hazards present when accessing areas with damaged network assets;
- status of emergency mobile generation;
- crew dispatch and arrival status; and
- estimated restoration times.

Developing this interface would significantly improve emergency response coordination between ourselves and other essential service providers in South Australia, improving supply restoration times, reducing safety risks and allowing faster response times for emergency services to natural disasters.

7.1.1 The identified need pursuant to the NER expenditure objectives

This project responds to the following context:

- more frequent and extreme weather events, including storms, heatwaves, floods and more intense fire seasons are being driven by climate change, with these risks forecast to increase further in coming years;
- areas of natural disaster occurrence typically correlate with regional parts of the network, where our network has aging assets and does not have the same level of resilience as metropolitan networks;
- bushfire events in recent years have highlighted the difficulties of coordinating access to disaster zones where network assets are damaged, with downed conductors and energised assets posing safety risks to emergency services entering these areas;
- no data sharing arrangements are currently in place to aid emergency services providers in understanding the status of our network in disaster zones, including the presence of potentially fatal safety risks in areas where they require access;
- the ability to understand the impacts of natural hazards on interconnected infrastructure networks, as well as the current limitations in policy regarding data sharing between these networks is currently in its infancy; and
- it is apparent via our engagement that providers of essential services (e.g. Country Fire Service, SA Water, telecommunications providers) have limited information on their exposure to network outages, the vulnerabilities they face, and the extent to which they should act (alone or in collaboration with us) to address these vulnerabilities.

The identified need for this project is pursuant to:

- the capex objective of maintaining the quality, reliability and security of supply of SCS in clause 6.5.7(3)(iii) of the NER;
- the capex objective of maintaining safety, in clause 6.5.7(4) of the NER; and
- the capex factor of addressing the concerns of distribution service end users as identified through engagement, in clause 6.5.7e(5A) of the NER.

7.1.2 The project is genuinely innovative

Collaboration between DNSPs and providers of essential services is currently undertaken via a series of manual processes, differing from region to region and dependent on the nature of the emergency being responded to. There are no formal data sharing arrangements in place, nor a consistent understanding of the data requirements to facilitate improved collaboration. Research has been undertaken by Natural Hazards Research Australia, with two projects commissioned to better understand the impacts of natural hazards on interconnected infrastructure networks. The application of this research, however, remains untested in industry.

This project would seek to:

- collaborate with emergency services and essential services providers such as the Country Fire Service (**CFS**), Metropolitan Fire Service (**MFS**), SA Water and Telstra to understand requirements for visibility of our network in disaster areas; and
- co-design and develop an API to share key data relating to our network to aid access during emergency situations, including:
  - the state of our network;
  - safety hazards present when accessing areas with damaged network assets;
  - status of emergency mobile generation;
  - crew dispatch and arrival status; and
  - estimated restoration times.

SA Power Networks is best placed to undertake this pilot as managing the operational response to supply restoration in an emergency falls within the scope of our role as a DNSP, and more specifically, within the scope of our SCS and in particular, our 'Common distribution service.' Our status as the sole DNSP operating in South Australia presents an efficient model to test the development of an interface that could later be rolled out more broadly across interstate DNSPs and emergency services, with a South Australian pilot requiring only a single DNSP to interface with other parties, as opposed to coordinating data from multiple DNSPs operating in other NEM states. Additionally, our extreme bushfire risks across mixed metropolitan and regional networks will provide learnings relevant to DNSPs of all other jurisdictions.

7.1.3 Alternative funding sources are exhausted

This project is unlikely to be eligible for co-funding, whether via the DMIAM or an ARENA grant, as:

- the project does not concern demand management or the modification of the drivers of network demand, but instead focuses on addressing community resilience and enhancing real-time communications and data sharing between emergency services, critical infrastructure providers and other utilities during major events
- the nature of the pilot does not align with ARENA's current funding priorities with regard to renewable energy, with the pilot purely focusing on improving real-time communications between relevant agencies during major events.

7.1.4 The project is prudently scaled

Implementation risks being addressed
This project seeks to improve the coordination of response in an emergency by enhancing the visibility of network status and safety hazards present in a natural disaster zone. The data shared via the proposed pilot interface directly affects the safety of on-site emergency services, and hence this pilot is required to address several risks, namely:

- provision of inaccurate network status or energisation data to emergency services personnel, potentially resulting in unintended entrance to an emergency zone where live network assets are present, and hence exposing on-site personnel to fatal risks;
- breaches of security resulting in unintended exposure of network status, crew dispatch or restoration activities during an emergency, with uninformed use of this data potentially exposing the user to fatal risks; and
- inability of emergency services to fully integrate this data into their own operational systems, resulting in little to no gain in the coordination of emergency response, and a continued reliance on manual or ad-hoc coordination between parties.

Deciding on project scale

Piloting an interface through which access to disaster-struck areas can be safely coordinated will allow us to explore the implementation risks without compromising the ability of both ourselves and state emergency services to maintain safe and timely emergency response. The pilot seeks to understand the validity of the proposed solution prior to a potential rollout of a more developed interface to all emergency services providers in South Australia, covering the entire distribution networks.

Specifically, the scope of the pilot would be limited to:

- deploying the data-sharing interface the South Australian CFS only; and
- calculating and publishing data relating to the status of our network and associated emergency response activities in regional areas only, correlating to the operating bounds of the CFS.

This project is appropriately scaled on the basis that:

- the CFS is our key partner in emergency response for the majority of bushfire events, which are the most prominent emergency response scenario where significant coordination is required; and
- limiting the provision of data to regional areas will allow us to understand what data is most suitable for provision to emergency services, and the interface over which it should be shared, without:
    - requiring complex integrations into our ADMS to determine live state of meshed metropolitan networks, with regional networks typically being of a simpler construction and operating logic; and
    - requiring further collaboration with services such as SA Water or the SA Police, with metropolitan emergency response often presenting more complex coordination requirements.

The project would be run over a two year time period, allowing for learnings across multiple fire seasons to be established. Initial deployment would commence in quarter 2 of 2026, with testing complete by the beginning of the 2026 bushfire season.

Success factors and pathway from pilot to BAU

The success criteria for this project, to be further expanded at the detailed project implementation stage include:

- feedback from the CFS on the usability of the interface and data provided over it
- the ability of the CFS to integrate our data into their operational response;
- consultation with other emergency and essential service providers, such as Telstra, SA Police and SA Water on the potential of this data to support their own emergency response; and
- demonstrated application of the data being integrated into regular emergency response ‘drills’ conducted between ourselves and the CFS.

A wider deployment of the interface would see us expand the coverage of network data to include all metropolitan areas and expand the audience for the interface to include the MFS, followed by parties such as the SA Police, SA Water and the SES.

7.1.5 The project aims to drive long term consumer benefits

The key expected benefits of this project and its broader application include:

- **increased community resilience**, with providers of critical infrastructure able to better prepare and respond to major events;
    - for example, telecommunications providers can proactively dispatch generation to critical mobile towers impacted by events;
- **improved restoration times**, with enhanced coordination of access to emergency zones allowing for more efficient supply restoration during extreme weather events;
- **lower emergency response costs,** with enhanced visibility over network status, crew dispatch and supply restoration reducing the manual effort to coordinate emergency response and hence lowering resourcing costs across all parties;
- **improvements to safety,** with real-time visibility over electrical safety risks minimising the potential for emergency services to be exposed to fatal risks, and enhancing their ability to inform and manage customers in disaster areas who may be at risk of exposure to network hazards.

7.1.6 Costs have been reasonably estimated

This pilot has been estimated at a total cost of $0.52 million of capex, and $0.09 million of opex.

These estimates are reasonable and reflect only the costs to establish a pilot capability to plan a flexible network, and do not include any costs to productionise, scale-up or expand the offer beyond the scope of the pilot as identified in *Section 7.1.4.*

A full cost breakdown, including itemised estimates, is included on the *8.1. Emergency Data Sharing* sheet of the attachment *5.13.4.1 Innovation Fund Project Estimates.* These costs have been estimated based on historical effort incurred to develop interfaces to a small number of other parties, including our single-user API between SA Power Networks and Telstra, our two-party APIs developed for our Advanced VPP Grid Integration and Market Active Solar projects.