PROJECTS FOR WHICH DMIA APPROVAL IS SOUGHT

Projects for which approval is sought under the Demand Management Innovation Allowance (DMIA) for the 2020 – 2025 Regulatory Period include the projects outlined in Table 1**Error! Reference source not found.** below with a total of $1,532,221 incurred in the 2022-23 Regulatory year.

The projects for 2022/2023 are categorised into three key streams of work:

- **Electrification and demand flexibility** – widespread electrification of homes and vehicles will occur over the coming decades and has the potential to more than double current peak demand and cost billions of dollars in additional augmentation expenditure and new generation and storage costs if managed poorly. Demand flexibility is key to integrating these loads and enabling an efficient transition. Projects in this stream aim to demonstrate the customer and network benefits of demand flexibility, and accelerate their deployment at scale.
- **Advanced planning** – planning for distribution networks is becoming increasingly more complex as DER continues to connect to the network. The long-term impacts of DER integration need to be considered, while also considering the potential of DER to provide network services and alternatives to network investment, requiring a much more sophisticated and integrated planning approach. Projects in this stream aim to develop more innovative methods and tools for network planning, including optimising efficient outcomes across both network and non-network solutions.
- **Demand management capability** – research, modelling and development projects that use innovative solutions to cost-effectively resolve voltage or thermal constraints by shifting or reducing demand for standard control services through non-network alternatives.

DMIA Innovation Stream	Project	Expenditure 2022/23
1. Electrification	1.1 Electrification and Demand Flexibility Pilot	$401,384
	1.2 Electric Vehicle Integration	$143,900
2. Advanced planning	2.1 Low voltage planning engine	$671,694
	2.2 Advanced network modelling	$182,891
3. Demand Management Capability	3.1 Tailem Bend region Demand Management trial (proof of concept)	$132,352
	Total	**$1,532,221**

Table 1 DMIA projects 2022/2023

1 Electrification

1.1 Electrification and Demand Flexibility Pilot

1.1.1 Nature and scope of the project

SA Power Networks recognises that widespread electrification of homes and vehicles will occur over the coming decades. SA Power Networks modelling suggests that South Australia will require approximately twice the amount of electricity by 2050, which will need to be distributed through SA Power Networks' distribution network. As a network operator, SA Power Networks has a responsibility to efficiently integrate these loads into the distribution network and ensure the best outcome for all customers.

Enabling demand flexibility is key to efficiently integrating these loads and enabling an orderly transition. It has the potential to minimise the network impacts of increased electrical demand,

removing the need for a significant uplift in network capacity investments and maximising the benefits that electric homes and vehicles can provide all customers.

Conversely, if the increased demand is managed poorly, it could more than double current peak demand and cost billions of dollars in additional augmentation expenditure and new generation and storage costs.

SA Power Networks acknowledges that actions it undertakes now will greatly influence the potential impact this additional demand has on the community and is committed to early planning to ensure an orderly transition. This project seeks to design and deliver a real-world pilot that will empirically demonstrate the customer, commercial and network benefits of demand flexibility and smart homes, and accelerate their deployment at scale.

1.1.2 Aims and expectations

The project will accelerate the establishment of smart homes in Australia by demonstrating the new consumer, network, retailer and installation industry value that can be accessed through the deployment of flexible demand-side technology in homes, trialled through simple, customer-focused 'flexible' energy service offerings to facilitate access to these benefits.

The project will demonstrate these new values in a real-world pilot with project partners who are leaders in their fields and have the capacity to deploy the new services at scale in Australia.

The pilot will improve commercial readiness of demand flexibility by:

- working with an established home energy management technology provider that has the necessary capability and capacity
- working with chosen partners to develop and trial simple customer-focused energy service offerings to reduce costs and improve customer service and choice regarding network access, home orchestration, customer control and reward structures
- research consumer sentiment and identify and overcome barriers to the adoption of these technologies and services
- identify government levers to remove barriers and support commercial viability of these technologies and services
- develop interoperability standards to remove the need for technology providers to develop bespoke protocols, improving customer portability and reducing barriers to commercialisation

1.1.3 Implementation of the project

Implementation of the project will be through a real-world pilot that will incentive 500 households to electrify their homes and trial home energy optimisation and behind-the-meter demand flexibility technologies in response to network and market conditions. Households will be offered incentive payments towards the cost of pre-approved, efficient electric appliances, as well access to low-cost finance to cover the residual cost of the appliances. Households with EVs will also be provided access to smart chargers.

Participating households will participate in a 2-year research program spanning the technical, behavioural, policy and industry components of residential electrification and home automation and identify the foundations required to make 'smart homes' a reality at scale.

SA Power Networks is currently developing an application for funding from ARENA's Advancing Renewables Program to enable delivery of the project. ARENA funded components of the project will

be removed from DMIAM expenditure. All activities undertaken to date have supported the development of the strategy, understanding the technical and commercial landscape for demand flexibility and developing the project with stakeholders and partners.

1.1.4 Implementation costs

Milestone	Date	SAPN tasks / deliverables	Cumulative contribution
1	December 2022	Initial strategy development, project scoping, stakeholder engagement and options analysis	$153,000
2	May 2023	Development of ARENA 'Expression of Interest' submission, project vision, objectives, outcomes and implementation approach	$228,000
3	June 2023	Detailed project design, technical architecture development, partner selection and research plan	$401,384
4	November 2023	Development of 'Full Application' for ARENA funding, finalisation of partner participation, research plan and budget	TBD
5	TBD 2023/24	ARENA funding approval, detailed implementation plan, contracting	TBD
6	TBD 2024 - 2026	Project execution, research and knowledge sharing	TBD

Project costs for the Regulatory year 2022/23 were $401,384.

1.1.5 Identifiable benefits

- Understand the impacts of wide-spread residential electrification and demonstrate the extent to which smart, electrified homes can offset network infrastructure costs
- Empirically demonstrate the customer and commercial benefits of demand flexibility
- Facilitate the development of interoperability standards for behind-the-meter devices
- Understand customer sentiment towards home energy management and identify strategies to maximise participation in flexible energy offers and smart, electric homes
- Stimulate and accelerate the establishment of a new industry capable of deploying residential behind-the-meter flexible demand technologies, including the key social, technical and commercial enablers

1.2 Electric Vehicle Integration

South Australia's transition to Electric Vehicles will reduce transport emissions and costs to consumers, while rapidly increasing electricity demand. As part of our future network planning, we have forecast over 800 GWh of additional energy flowing through our network annually by 2030 – an increase of almost 10% - due to EVs. By 2050, EVs will have increased energy throughput on our network by 50% and our network will be the primary distribution system for transport energy for the State.

If EV charging occurs frequently during peak times, the transition to EVs has the potential to drive substantial new growth in peak electricity demand, requiring significant upgrades to the distribution

network. If EV charging is managed to occur mostly outside of the peak periods, our modelling suggests that South Australia has the potential to decarbonise the transport sector largely within our existing network capacity. If integrated efficiently, South Australia could expect to see significant reductions in average network price between 2030 and 2050 due to this additional energy throughput.

Availability and convenience of EV charging is one of the most commonly cited barriers for EV adoption. SAPN has a role to play in ensuring the installation and operation of private and public EV charging is efficient and rapid. Ensuring an "EV ready" network will require considered adjustments to several internal processes, rules and systems such as our Service and Installation Rules (SIR) which cover any requirements for Level 2 home EV Supply Equipment (EVSE), the Tariff Structure Statement and Connections Policy which governs when and how customers are charged for network flexibility, and the After Diversity Maximum Demand (ADMD) numbers which consider potential impacts of peak EV charging loads on the grid.

1.2.1 Nature and scope of the project

Fortunately, it is not always critical *when* or *how fast* the EV is charged, making it a comparatively flexible load. Being able to leverage that flexible load, requires SAPN to be able to reliably communicate with active EV Supply Equipment (EVSE) and provide commensurate incentives to customers. This was explored in *Activity 1*, by testing SAPN's ability to send signals to EVSE that can ramp up or down their charging rate in response. After testing with residential devices, we expanded our research to test on SAPN's internal EV fleet infrastructure (*Activity 4*).

In order to include customer EV charging behaviour in our network planning and network design, we require visibility of the location and size of EV chargers. This was explored in *Activity 2,* by establishing a digital process for installers to register EV chargers.

The massive potential battery storage of EVs can only be truly unlocked through bidirectional charging. SAPN has become the first jurisdiction in Australia to allow customers to install Vehicle to Grid (V2G) infrastructure outside of trials. This was possible by our technical investigation and standards adjustments in *Activity 3.*

1.2.2 Aims and expectations

SA Power Networks' EV integration strategies are guided by our 15-year Strategic Direction (2021-35), our Customer Strategy 2022-2026, and our Network Strategy 2020-2030. The objectives are:

1. Incentives – Offer EV Services that give customers optionality and incentives that are designed to meet their needs while aligning EV charging with optimised network utilisation.
2. Connections – Streamline our connection rules & processes so it's easy, transparent, and simple to connect EV chargers.
3. Operations – Efficiently plan and operate our network with EVs integrated as flexible loads that can respond to network signals while improving energy security and reliability
4. Supporting the transition - Educate our customers, employees, suppliers and stakeholders and advocate for aligned EV charging practices

Success of these objectives can be measured by a rapid decarbonisation of South Australia's transport sector that is accessible to customers, supported by industry, and does not necessitate extensive network upgrades.

1.2.3 Implementation of the project – 2022/2023

Activity	SAPN tasks / deliverables	Cost
1.	Validate the ability to leverage demand flexibility of residential EVSE to reduce impact on peak demand • Set up test environment to send commands to remote EVSE • Experiment on SAPN owned EVSE • Conduct friendly testing on non-SAPN equipment • Produce a trial tariff to incentivise enrolment in EV charging network demand management ("Diversify")	$90,000
2.	Increase EV registration compliance in the DER register (phase 1) • IT development on existing customer systems to include the registration of EVSE that adds to our DER register • Update SAPN SIRs to accommodate for EVSE exemption to exceed switched load limit	$40,000
3.	Integrate Vehicle to Grid (phase 1) • Test & certify eligible bidirectional EVSE • Integrate V2G in EVSE SmartApply process • Support customers and installers to uptake & use	$10,000
4.	Integration of Fleet EVs into Building Demand Management • Install smart EVSE for the new SAPN EV Fleet vehicles that can be integrated into *Activity 1*	$3,900

Project costs for the Regulatory year 2022/23 were $143,900.

1.2.4 Expected activities for year - 2023/2024

Activity	SAPN tasks / deliverables
5.	Increase EV registration compliance in the DER register (phase 2) • Incorporate public rapid chargers in DER registration • Communicate notices to industry
6.	Continue to integrate Vehicle to Grid (phase 2) • Update connection rules, standards and systems to cater for uptake in V2G & include in flexible exports/imports • Advocate for recognition of eligible bidirectional EVSE in CEC listing – include knowledge sharing with other DNSPs
7.	Integrate flexible load demand management • Import limits (DOEs) to be generated and sent • Introduce flexible loads in the connections and trial tariffs • Validate the ability to leverage demand flexibility of public rapid EV chargers • Support SA Government Smart EVSE Guidelines

1.2.5 Identifiable benefits

The identified benefits of the Milestones completed in 2022/23:

1. We identified a key barrier to direct EVSE communication– inconsistency of implementation of OCPP across multiple vendors prevents us from sending the same network signals. We are now engaging in national discussions to standardise this interface.

2. Our DER register now includes the details and location of 229 EVSE, enabling improved proactive network planning
3. South Australia has become the first (and only to date as of Sept 2023) network in Australia to allow the standard connection of Vehicle to Grid (V2G), sharing learnings across the country.
4. Learnings from our smart EVSE installs and operation have been documented and utilised to support customers installing EVSE in areas with potential network constraints

The expected benefits of the Milestones to be completed in 2023/24:

5. Increase EV registration compliance in the DER register (phase 2)
    a. We will be able to report accurate and reliable data as requested by AER/AEMO
6. Continue to integrate Vehicle to Grid (phase 2)
    b. South Australian EV drivers will be able to contribute to network minimum and maximum demand events with their "battery on wheels"
7. Integrate flexible load demand management
    c. Larger customers can connect to the network in quicker and more cost-effective manor, enabling accelerated DER uptake
    d. We will not experience a linear rise in peak electricity demand in-line with EV uptake

2 Advanced planning

2.1 Low Voltage Planning

2.1.1 Nature and scope of the project

SA Power Networks procures various levels of power quality measurements from residential smart meters and power quality monitoring devices installed throughout the state. The need for additional monitoring data has been driven by DER Enablement spend in the 2020-25 regulatory period.

Historically augmentation expenditure on low voltage networks was driven by customer enquiries, with very little forecasting and planning. This project aims to develop tools and processes that leverage new diverse data sources and hosting capacity models to increase SA Power Networks' ability to strategically plan the low voltage network. This project will establish a constraints model and demand forecasting tool for each LV area within the distribution network which will be used to rank performance of LV areas and guide targeted remediation work to proactively manage low voltage networks and prioritise augmentation spend.

2.1.2 Aims and expectations

- Understand the minimum data inputs and network information required to categorise a sufficiently accurate demand forecast and detect associated network constraints for a given LV network area.
- Develop an innovative methodology to accurately extrapolate data inputs and model the remaining LV network areas where limited or no visibility is otherwise available.
- Identify relevant performance metrics and establish risk quantification based on power flows, asset ratings and durations of network constraints.
- Establish cost benefit calculations based on lost energy, service level performance and risk + performance metrics against costs of various solutions to best guide investment decisions.

2.1.3 Implementation of the project

The project will be phased over the 2021/22 and 2023/24 Regulatory years delivering benefits in each phase of the project. Implementation is split across 4 key milestones:

Milestone	Target Date	SAPN tasks / deliverables
1	1st January 2022	- Establish initial powerflow calculation and constraint model + initial procedures for its utilisation
2	1st December 2022	- Develop integration of constraint model with forecasting methodologies in order to establish a 25 year low voltage network forecasting tool, capable of measuring asset utilisation and performance over time and risk quantification of asset failure for all LV areas.
3	30th June 2023	- Expand the risk and performance valuation to include investment decision making functions capable of evaluating various solution types and specifying works programs capable of delivering a desired performance target, including cost benefit assessment.
4	31st December 2024	- Integrate the above tool with asset condition information to establish a holistic approach for governing asset replacement and augmentation requirements.

2.1.4 Implementation costs

Milestone	Indicative date	Cost
1	1 January 2022	$50,000
2	1 July 2022	$20,000
3	30 June 2023	$671,694
4	31 December 2024	TBD

Project costs for the Regulatory year 2022/2023 were $671,694.

2.1.5 Identifiable benefits

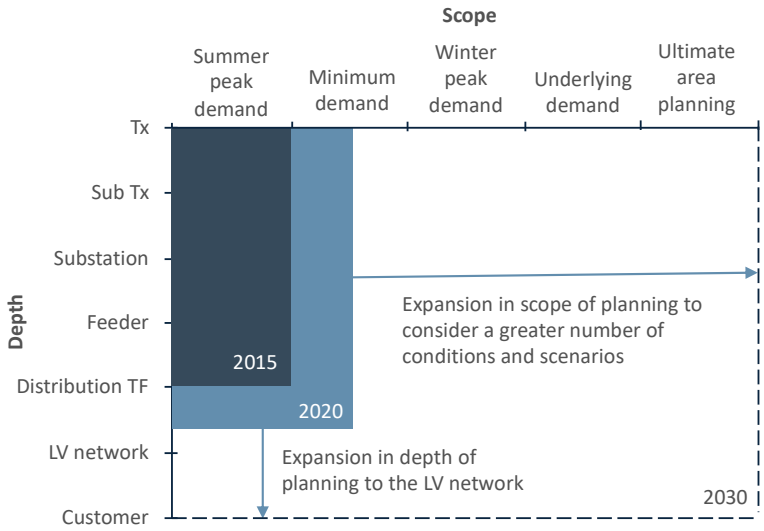
- alleviate power quality issues such as voltage rise
- increase the network hosting capacity of distributed energy resources where required to deliver a target level of service that customers desire and is economically prudent.
- improve overall asset optimisation and use in both households and the distribution network.
- improve customer experience and increase efficiency through proactively identifying and resolving network issues without requiring customers to make enquiries prior
- Minimising network augmentation through building a better and more holistic understanding of network constraints and determining the most efficient means to meet them.

2.2 Advanced network modelling

2.2.1 Nature and scope of the project

SA Power Networks publishes a Distribution Annual Planning Report (DAPR) intended to assist non-network proponents in proposing alternative solutions to defer network upgrades and to inform interested parties. It also aims to guide new load and generation proponents to suitable parts of the network that would result in reduced network augmentation associated with any new connection. Stakeholders have commented that the information presented currently is not easily interpreted or sufficient to guide their decision making. This has resulted in large numbers of high-level connection enquiries as customers and proponents often consider several geographic locations before determining a suitable site.

Furthermore, to continue to plan our network effectively we will need to model the impact of new energy technologies and services, such as PV, VPPs and EVs, which not only introduce complex new constraints in peak demand, minimum demand, and the need to manage diverse power flows, but also significantly increase the necessary depth, breadth, and overall complexity of planning. We need to be able to plan for a broad range of scenarios to understand how best to target investments and identify efficient non-network opportunities.



The project scope includes establishing and enhancing data, tools and processes associated with SA Power Networks' digital network models, to enable advanced network constraint analysis. This will produce improved visualisation of hosting capacity via opportunity maps, provide more accurate identification and transparency of network constraint information, and enable the identification of the most efficient solutions to these constraints.

2.2.2 Aims and expectations

The project aims to provide advanced network planning tools and models that allow for accurate digital models of the Distribution Network suitable for planning purposes which can be used to identify the most efficient solutions to network constraints, including the assessment of non-network alternatives. The concept involves developing innovative techniques to model the HV network by automation and optimisation of the network build process. New advanced planning functionality and processes will then be developed to enable efficiency and quality improvements.

A key objective is to improve the transparency of network constraint information and visualisation of hosting capacity. The higher degree of accuracy within the models and the advanced planning functionality delivered by the modelling tool is expected to automate processes for constraint identification and facilitate efficient options analysis. This functionality will also enable the publication of hosting opportunity maps as part of the DAPR highlighting those areas with load and generation hosting constraints (thermal and voltage limits).

2.2.3 Implementation of the project

The project will be phased over the 2020/21, 2021/22, 2022/23 and 2023/24 Regulatory years delivering benefits in each phase of the project.

Phase 1 – HV model creation and automation of planning processes

- HV model automatic build (and update) from the GIS to Sincal modelling tool;
- Model validation and establishment of processes to ensure model accuracy;
- Functionality to simplify and improve the quality of Network Planning analysis;
- Functionality and process efficiency improvements for assessment of load and generation connections.

Phase 2 – Advanced Network Planning and automation capabilities

- Functionality to facilitate the efficient analysis of investment options including augmentation deferral through demand management and non-network solutions associated with load connections and long-term network development;
- Functionality to analyse the future wide area effects of DER, BESS and EVs;
- Hosting capacity analysis for both generation and load on the HV network;
- Publication of Hosting Capacity Opportunity maps; and
- Integration of DER register data into HV Sincal models via automated process.

Phase 3 –LV Model creation

- Trial of LV model automatic import of LV GIS model to Sincal
    - Inform DER management trials
    - Inform more efficient deployment of voltage control solutions
    - Understand LV hosting capacity
    - Enable improved LV planning including Quality of Supply analysis and proactive planning
- Enhanced functionality to integrate LV model import into production; and
- Integration of DER register data into LV Sincal models via automated process.

2.2.4 Implementation costs

The expected implementation costs are outlined in the table below.

Project Phase	**Cost**	**Regulatory Year(s)**
Phase 1 – HV model creation and automation of planning processes	$282,445 $100,000	2020/2021 2021/2022
Phase 2 – Advanced Network Planning and automation capabilities	$200,000 $182,891 $245,000*	2021/2022 2022/2023 2023/24
Phase 3 –LV Model creation trial	$50,000	2021/2022

*Estimates, subject to more detailed scoping.

Project costs for the Regulatory year 2022/2023 were $182,891.

2.2.5 Identifiable benefits

The project is expected to deliver significant benefits for customers and non-network solution providers including:

- Visualisation of hosting capacity (load and generation) via opportunity maps will facilitate greater network utilisation and reduction in augmentation.
- Greater transparency of network constraint information leading to greater awareness of network capability and opportunity for greater utilisation.

- Improved identification of network constraints that can be resolved or deferred by demand management including non-network service solutions.
- More efficient targeting of network investment.
- Greater stakeholder access to network information is expected to reduce the number of speculative load and connection enquires that connection proponents need to make.
- Innovative advanced planning functionality to analyse the future network needs of DER, BESS and EVs and ensure this is incorporated into forward planning.
- Facilitating engagement with third party non-network solution providers

Whilst modelling tools have been implemented in other jurisdictions, the modelling tools and techniques developed in this project are new approaches to model build and visualizations. Benefits are expected to be realised for customers, non-network solution providers and internally within SA Power Networks.

3 Demand Management Capability

3.1 Tailem Bend region Demand Management Trial

3.1.1 Nature and scope of the project

SA Power Networks recognizes the high cost of installing inter-tripping schemes, particularly in rural parts of the network with limited telecommunications infrastructure, is inhibiting utilization of customer owned standby generation to alleviate network constraints.

The scope of this project is to undertake modelling, design, and development of a cost-effective demand management control system, to enable a customer owned standby diesel generator to be run in parallel with the distribution network during peak demand periods, without the need for protection grade inter-tripping to mitigate the risks associated with islanding.

The design solution and proof of concept build achieved as part of this project will facilitate establishment of a non-network service thus accommodating increased customer demand in the region as an alternative to extensive network upgrades.

3.1.2 Aims and expectations

This project aims to demonstrate innovative demand management capability, in the Tailem Bend region. The control system will achieve load reduction by automated start and ramp up of the customer owned standby diesel generating system, or by voluntary load shedding, to reduce demand on the distribution network. The intent is to also demonstrate that removing barriers to customer participation in demand management services will enable cost-effective services to be provided.

3.1.3 Implementation of the project – 2022/2023

Works undertaken in the 2022/2023 period include:

- Model and validate the ability to leverage the generator to mitigate voltage constraints;
- Develop the operating philosophy, control system and interface requirements; and
- Scope, design and commence commissioning of the control and automation works.

Works forecast to occur in the 2023/2024 period include:

- Commissioning of the control and automation works; and
- Implementation and testing to validate capability.

3.1.4 Implementation costs

Project costs for the Regulatory year 2022/2023 were $132,352.
Implementation costs for the 2023/24 period are forecast at $315,000.

3.1.5 Identifiable benefits

Implementation of this project is expected to deliver reductions to required capital expenditure through deferral of augmentation. Additional benefits to customers include:

- Alleviate power quality issues such as under voltage during periods of peak demand;
- Increase the network hosting capacity for new customer loads in the region;
- Removal of cost-prohibitive inter-tripping requirement to mitigate islanding risk when the standby generator is connected in parallel with the distribution network; and
- Demand management capability to enter into a network support service agreement to reducing demand for standard control services through a non-network alternative.

4 Costs not recoverable

Costs for the DMIA projects described above:

a. are not recoverable under any other jurisdictional incentive scheme,
b. are not recoverable under any other State or Commonwealth government scheme, and
c. are not included in the forecast capital or operating expenditure approved in the AER's distribution determination for the regulatory control period under which the scheme applies, or under any other incentive scheme in that determination.

5 Calculation of DMIA

The total amount of the DMIA spent in the 2022 -2023 Regulatory Control Period was $1,532,221. This amount equates to the total spend against the projects for which approval is sought under the DMIA as detailed in this report. The costs associated with these DM trials have been separately captured at the individual project level in SAP, SA Power Networks' integrated business management system. The expenditures incurred against these trials for each year of the Regulatory Control Period have been reported in Table 7.11.2 of SA Power Networks' Annual Reporting RIN Response and subject to independent external audit in accordance with the RIN requirements.