Ergon Energy Demand Management Innovation Allowance Report 2021-22

September 2022

Part of Energy Queensland

Contents

1. Introduction

1.1 Purpose and compliance

Ergon Energy is pleased to present the Demand Management Innovation Allowance Mechanism (DMIA) Report for the 2021-22 regulatory year. The purpose of this report is to allow the Australian Energy Regulator (AER) to:

- assess Ergon Energy's 2021-22 DMIA initiatives and Ergon Energy's entitlement to recover the expenditure under the AER's Demand Management Incentive Allowance Mechanism; and
- confirm Ergon Energy's compliance with the annual reporting requirements of the AER's Regulatory Information Notice (RIN).

This report has been completed in accordance with Schedule 1, item 7 of the AER's RIN (refer Figure 1), which requires a distribution network service provider (DNSP) to which the DMIAM applies, to submit an annual report to the AER on its expenditure. This report, and the information contained in the report, is suitable for publication by the AER.

Figure 1: DMIA reporting requirements Schedule 1: Item 7 – Demand Management Incentive Allowance Mechanism

7.1 Identify each demand management project or program for which Ergon Energy seeks approval.

7.2 For each demand management project or program identified in the response to paragraph 7.1:

a) Explain how it complies with project criteria detailed at section 2.2.1 of the demand management innovation allowance mechanism

b) submit a compliance report in accordance with section 2.3 of the demand management innovation allowance mechanism

2.2.1 Project Criteria:

(1) An **eligible project** must:

(a) be a project or program for researching, developing or implementing **demand management** capability or capacity; and

(b) be innovative, in that the project or program:

i) is based on new or original concepts; or

ii) involves technology or techniques that differ from those previously implemented or used in the **relevant market**; or

iii) is focused on customers in a market segment that significantly differs, from those previously targeted by implementations of the relevant technology, in relevant geographic or demographic characteristics that are likely to affect demand; and

(c) have the potential, if proved viable, to reduce long term network costs.

(2) A **distributor**'s costs of a project or program are not eligible for recovery under the **mechanism** if those costs are:

i) recoverable under any other jurisdictional incentive scheme;

ii) recoverable under any state or Australian Government scheme; or

iii) otherwise included in forecast capital expenditure or operating expenditure approved in the **distributor**'s distribution determination.

(3) For avoidance of doubt, the **mechanism** does not require a **distributor**'s **eligible project** to be geographically constrained to its **distribution network**.

2.3 Compliance Reporting

(3) Each compliance report must include, for the regulatory year to which the compliance report relates:

(a) the amount of the allowance spent by the distributor;

(b) a list and description of each eligible project on which the allowance was spent;

(c) a summary of how and why each eligible project complies with the project criteria;

(d) For each eligible project on which the allowance was spent, and in a form that is capable of being published separately for each individual eligible project, a project specific report that identifies and describes:

i) The nature and scope of the eligible project;

ii) The aims and expectations of the eligible project;

iii) How and why the eligible project complies with the project criteria;

iv) The distributor's implementation approach for the eligible project;

v) The distributor's outcome measurement and evaluation approach for the eligible project;

vi) The costs of the eligible project:

1. incurred by the distributor to date as at the end of that regulatory year;

2. incurred by the distributor in that regulatory year; and

3. expected to be incurred by the distributor in total over the duration of the eligible project.

vii) For ongoing eligible projects:

1. a summary of project activity to date;

2. an update of any material changes to the project in that regulatory year; and

3. reporting of collected results (where available).

viii) for eligible projects completed in that regulatory year:

1. reporting of the quantitative results of the project;

2. an analysis of the results; and

3. a description of how the results of the eligible project will inform future demand management projects, including any lessons learnt about what demand management projects or techniques (either generally or in specific circumstances) are unlikely to form technically or economically viable non-network options.

1.2 DMIA projects summary

In its Distribution Determination for the 2020-2025 period, the AER decided to apply the Demand Management Innovation Allowance Mechanism to Ergon Energy, approving an innovation allowance amount of $5,564,333 over the 2020-25 regulatory control period.

The DMIA is provided to investigate opportunities that are not yet commercial, in addition to any business-as-usual capital and operating expenditure allowances for demand management and embedded generation projects approved in Ergon Energy's Distribution Determination. This provides a direct incentive for DNSPs to assess emerging opportunities for potentially efficient non-network alternatives, to manage the expected demand for standard control services in some other way or to enable more efficient connection of embedded generation other than through network augmentation.

Ergon Energy's 2021-22 DMIA program comprised six projects. The total cost incurred for the DMIA initiatives during 2020-21 was $378,877.97. The table below summarises Ergon Energy's DMIA program expenditure recovery for the 2021-22 regulatory year.

Project	2021-22 expenditure ($) direct cost only				
	Total project budget	Capital	Operating	Total	Status (at 30 June 2022)
Alternate Supply Bustard Head	932,673		17,008.28	17,008.28	Continuing
RRCRF Clairview Stanage Project	688,844		97,313.70	97,313.70	Continuing
West Leichhardt SWER	3,131,525		156,722.10	156,722.10	Continuing
IPDRS Pilot	636,636		13,345.63	13,345.63	Closed
Evolve	240,000		16,805.81	16,805.81	Closed
DMIA Allawah Fringe of Grid Field Trial	215,379		77,682.45	77,682.45	Continuing
Total	5,845,057		378,877.97	378,877.97	

Ergon Energy confirms that the costs of the projects specified in this report are:

- not recoverable under any jurisdictional incentive scheme;
- not recoverable under any other Commonwealth or State Government scheme;
- not included as part of:
  - the forecast Capital Expenditure or the forecast Operating Expenditure; or
  - any other incentive scheme applied by the 2020-25 Distribution Determination.

2. DMIA Project development and selection process

Ergon Energy considers DMIA investments an important component of its commitment to delivering customer value over the longer term. The DMIA program complements our demand management program, which is geared toward providing a more efficient solution to network augmentation. The DMIA initiatives have enabled Ergon Energy to investigate and test innovative approaches to a range of network issues, customer behaviours, renewable integration and tariff enablement.

For the 2021-22 DMIA program, all nominated DMIA projects are subject to a screening and feasibility processes, consistent with the AER's DMIA criteria. The standard DMIA project development and assessment process applied in Ergon Energy involves:

- Promotion of DMIA funding and criteria to internal stakeholders to encourage project ideas to be submitted, as an expression of interest (EOI) or more formal DMIA Project Scope;
- Review of EOI or DMIA Project Scope against DMIA criteria as a minimum, and against relevant internal strategy documents, including the Energy Queensland Future Grid Roadmap*, the Demand and Energy Management Strategy and Load Control Strategy;
- Project proponents are encouraged to discuss project ideas with other Energex or Ergon Energy subject matter experts, which helps guide and refine the idea;
- Projects that are deemed to meet the DMIA criteria are then formally submitted to the DMIA Program Manager for approval, or endorsement to the appropriate financial delegate.

*The Future Grid Roadmap is a document that outlines a range of themes and supporting activities and no-regret investments necessary for Energex and Ergon Energy to achieve a transition to the intelligent grid of the future over the next 10-20 years. It is not essential to meet criteria other than the stated DMIA criteria, however project proponents should, where possible, ensure their project aligns with these existing strategic network directions and priorities.

Budgets are prepared in accordance with Ergon Energy standard project methodology, detailing information including project goals, deliverables, milestones and resources required. Cost estimations were developed for the requirements identified, for each phase of the project. These cost estimations drew upon various sources including the cost of similar projects undertaken by Ergon Energy, current preferred contractor panel contracts and market research.

The pipeline of DMIA projects has slowed somewhat this year. To help identify further potential projects, we engaged with external partners to who may be suitable to collaborate on DMIA projects. This included direct engagement to all Queensland based universities through our Ergon Energy university liaison officers. We have also improved our web presence to include more case studies on previous DMIA projects, outlining the key DMIA criteria and inviting any interested parties to make contact.

3. DMIA Project updates

This section of the report details the status of Ergon Energy's DMIA projects in 2021-22 by describing each project, its objectives, progress and findings to date.

3.1 Alternative Supply Bustard Heads

Trial a stand-alone power system (SAPS) as a network support device, with the long term aim to reduce network costs.

3.1.1 Compliance with DMIA Criteria

The Bustard Head SAPS project complies with the DMIA criteria as the project will enable the substitution of costly network components with alternative supply arrangements that provide improved power quality and reliability whilst enabling improved value to all customers.

3.1.2 Nature and Scope

Trial a stand-alone power supply system as a network support, with the long-term aim of using SAPS as a lower cost solution to network maintenance/replacement.

3.1.3 Aims and expected outcomes

Direct outcomes and benefits:

- The customer outcomes will be a more reliable power supply.
- The network outcome will be a reduced operating cost and reduced network losses on the distribution system

Indirect outcomes and benefits:

- Ergon Energy has developed new approaches to working with customers towards more cost-effective supply solutions through the development of a SAPS Customer Engagement Strategy;
- Ergon Energy will develop new equivalent electricity supply standards for solar/battery hybrid systems including working with Energy Networks Australia (ENA) to develop new business standards and guidelines for utility grade SAPS;
- Ergon Energy is using the knowledge and experience gained from the SAPS trials in working with ENA and other distribution network service providers (DNSPs) to develop national guidelines for DNSP led SAPS.

3.1.4 The process by which it was selected, including its business case and consideration of any alternatives

All Ergon Energy DMIA projects are selected and scoped to respond to current and emerging network limitation drivers and adhere to the standard governance framework. The eligibility-screening process is performed on nominated projects as a high-level assessment, to determine whether the projects meet the DMIA criteria. Other internal criteria are then assessed – including how the findings of the project, should it be successful, could be applied within the business. Provided all the specified conditions are met, then the project proceeds to the feasibility assessment and approval stages, as per the gated governance framework and with internal subject matter expert review and feedback. Information from the development activities undertaken enables implementation scheduling, milestone planning and confirmation of resources.

3.1.5 How it was/is to be implemented (i.e. general project update)

The Bustard Head SAPS was installed and commissioned in December 2020 (installation photo's below). It has been in operation since this time supplying the full energy needs of the two customers it supplies. The SAPS is being monitored and its performance measured, and a customer survey has been undertaken to gather customer insights through the whole project process. The SAPS will continue to be monitored and lessons learnt captured for the development of future standardised DNSP SAPS. This trial will lead into new work to enable appropriate life-time management of alternative supply dependent on the criteria set under the new regulatory framework that will enable DNSP's to supply customers by SAPS.

3.1.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

The project has already developed some criteria for equivalency in design that now need to be tested. Customer engagement has been positive for the project and has included discussions around the topic of appliance use and load management to optimise the systems. As a result of this project, a Stand-Alone Power Systems Customer and Community Engagement Strategy has been developed which can be used for any future similar engagement.

Image 1: Bustard Head SAPS

3.2 West Leichhardt SWER

Trial two larger scale SAPS as network support devices as an alternative to grid supply.

3.2.1 Compliance with DMIA Criteria

The West Leichhardt SAPS project complies with the DMIA criteria as the project will enable the substitution of costly network components with alternative supply arrangements that provide improved power quality and reliability whilst enabling improved value to all customers.

3.2.2 Nature and Scope

Trial SAPS as network support and develop supporting policies, processes and systems that can more broadly enable DNSP led SAPS across Ergon Energy's and Energex's networks.

3.2.3 Aims and expected outcomes

- Improved reliability and power quality for the two customers involved in the trial
- Informing design rules and scenarios for SAPS
- Developing customer engagement strategies and plans to transition customers from grid to SAPS supply
- Identifying changes to Ergon Energy's connection policy and connection agreements to ensure a consistent approach for single wire earth return (SWER) customers and encouraging alternate solutions where appropriate rather than extending the SWER network
- Acquiring the knowledge and experience to inform:
  - future business requirements for SAPS supply; and
  - future product solutions to enable a more flexible approach to connections in the future by the planning teams.

3.2.4 The process by which it was selected, including its business case and consideration of any alternatives

All Ergon Energy DMIA projects are selected and scoped to respond to current and emerging network limitation drivers and adhere to the standard governance framework. The eligibility-screening process is performed on nominated projects as a high-level assessment to determine whether the projects meet the DMIA criteria. Other internal criteria are then assessed – including how the findings of the project, should it be successful, could be applied with the business. Provided all the specified conditions are met, then the project proceeds to the feasibility assessment and approval stages, as per the gated governance framework and with internal subject matter expert review and feedback. Information from the development activities undertaken enables implementation scheduling, milestone planning and confirmation of resources.

3.2.5 How it was/is to be implemented (i.e. general project update)

Two SAPS to supply the two customers involved in this trial were commissioned in February and March 2021 and have been operational since this time supplying the operational needs of the two customers (installation photo's below).

The SAPS are being monitored and their performance measured, and customer surveys have been undertaken to gather customer insights through the whole project process. The SAPS will continue to be monitored and lessons learnt captured for the development of future standardised DNSP SAPS.

This trial will lead into new work to enable appropriate life-time management of alternative supply dependent on the criteria set under the new Australian Energy Market Commission rules for SAPS.

3.2.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

The project has already developed some criteria for equivalency in design that now need to be tested. Customer engagement has been positive for the project and included discussion around the topic of appliance use and load management to optimise the system – for example, scheduling use of appliances during the daytime to maximise solar energy use.

Image 2: SAPS Trial Site 1

Image 3: SAPS Trial Site 2

3.3 Internet Protocol Demand Response System (IPDRS) Pilot

The purpose of this project was to undertake market discovery to establish a complete end-to-end energy management system that enables the Internet Protocol Demand Response Device (IPDRED) functionality. There are regulatory and market changes that are likely to result in control of distributed energy resources (DER) by other market participants, and therefore this trial aimed to test how third parties and their devices respond to DNSP requests for demand response in households. This project was jointly funded under Ergon Energy and Energex DMIA allowances.

3.3.1 Compliance with DMIA Criteria

The project aims to orchestrate improved energy management (peak lopping, valley filling, neutralise otherwise disruptive loads) to reduce network augmentation requirements. The purpose of an IPDRS is to increase the amount of load under management (more appliances, improved geographic coverage); improves the ability to have more granular / targeted load control; and to complement existing load control based around audio frequency-based load control. As the project was initiated in 2019-20 but expected to carry forwarded into the 2020-25 regulatory control period, it was assessed against the DMIA criteria applicable in both regulatory control periods. The project was deemed compliant as it was a program for researching, developing or implementing demand management capability or capacity, that could be used as broad based or in specific network demand constraint areas.

3.3.2 Nature and Scope

Undertake market discovery to establish a complete end-to-end market-delivered demand response (MDDR) process; from DNSP signalling a requirement to third parties reacting, and verifying their response, to satisfy that requirement. Market discovery will enable understanding for a broader market undertaking. This scope covers engagement of potential third-party solution providers delivering MDDR.

3.3.3 Aims and expected outcomes

The aim was to identify suitable service providers for a complete energy management platform (from platform serve to a demand response communications pathway). A key outcome of the project was planned to be a detailed business case to move forward with market roll-out IPDD requirements, if the pilot is successful.

3.3.4 The process by which it was selected, including its business case and consideration of any alternatives

With regulatory requirements seeking DNSP movement away from any activity behind customer meters this program seeks to fulfil the stated strategic intent of managing two-way energy flows, being cost-efficient in encouraging other market players to deliver attractive demand management/response mechanisms that value add to them and their customers. With growth of residential DER, understanding how to support a pathway for this market will increase both the type and magnitude of loads under management and accessible for network support. With individual customer addressability there will be greater granularity and flexibility in response to network constraints. With other market players encouraging take-up of their services to optimise energy use to tariffs and value from demand response the cost to procure these services from the market only as required should significantly reduce cost to serve, whilst augmenting the existing network value of the audio frequency load control / demand management platform.

3.3.5 How it was/is to be implemented (i.e. general project update)

The project was meant to operate through the engagement of service providers of technology solutions being sought for platform and communication pathways. Service providers were asked to secure new participants to their existing home energy management systems (HEMS) based on a set of DNSP requirements, including an incentive payment. Whilst the original aim was to recruit up to 500 participants, of the 232 households who responded to the initial mailout, only 9 customers joined the trial. Whilst this was lower than planned, it was sufficient to allow for the demand response testing and subsequent evaluation to take place.

The project has now been completed, with a detailed final report produced and published on the Energex website. A summary of the findings is below.

3.3.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

Given the regulatory moves toward market procurement of load control, part of the original objective to have a better understanding of the cost to deliver an end-to-end control methodology has morphed to being that of formalising with the market, a DNSP's requirements of their vendor solutions to enact demand management/response on the DNSP's behalf.

Eighteen events were called seeking a mixture of both peak and minimum demand between the 22 February and 6 June 2021. Very positive results identify that the IPDRS solution is technically successful in delivering significant network relief when required. Diversified demand reductions of over 2kW, and diversified minimum demand relief of at least 2kW per event participant were observed with relative ease.

A full report has been published on the pilot and has identified five outcomes:

1. The existing embryonic market conditions make it exceedingly difficult for third-party providers to make meaningful inroads to customer acquisition.
2. Solutions can be costly due to a lack of economies of scale, and customers are not really aware of the HEMS market, meaning significant financial assistance would be required to inject impetus to the market,
3. Finding other channels to market will assist in generating market uptake (e.g. greenfield sites),
4. That IPDRS orchestration of DER and loads within a home can present significant opportunities for network support as well as customer savings. The tables below show the demand response outcomes:

HEMS fleet event outcomes (diversified across the cohort/customer)

Peak reduction range (5-7pm weekdays)	Between 0.90 and 1.2kW
Minimum Demand events	
Solar export reduction (direct inverter management)	1.7kW (3.1kW by signal respondents[1])
Solar export reduction (load increase)	2.3kW (3.3kW by signal respondents)
Solar generation stop	4kW
Solar generation stop/maximum load increase	5.79kW

[1] Not all households were signalled to respond to the events. The lower number reflects the diversified value across the cohort, the larger number reflects the diversified response of those households that did respond.

As noted in the report, directly managing solar generation is very effective. Increasing loads to "solar soak" is also effective but is less reliable as a mitigant to minimum demand.

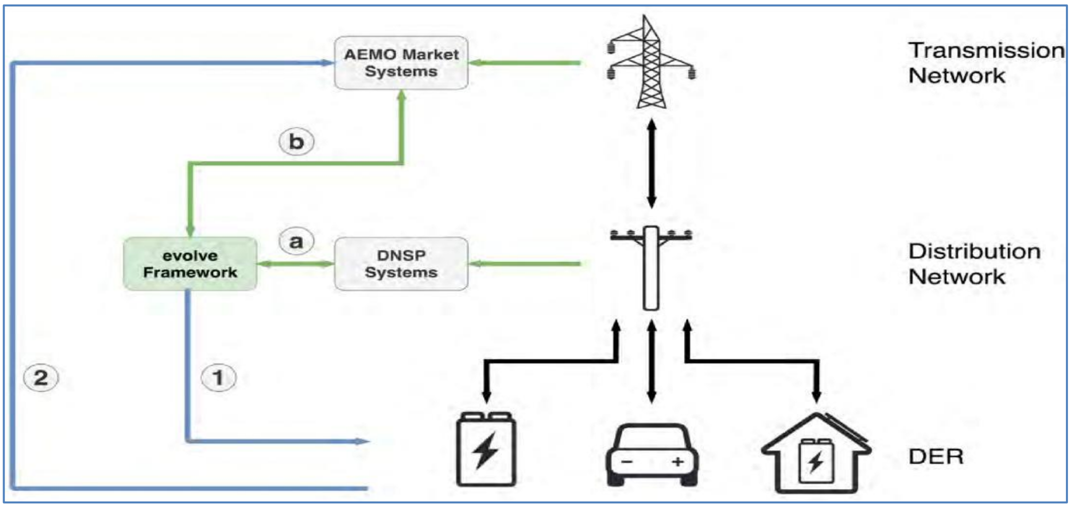
Customer energy and bill impacts from having HEMS[2]
Reduces evening peaks by approximately 30% (potentially greater for actual peak demand days – these were unable to be tested).
Reduced overall grid-supplied kWh by approximately 14%. Two participants without rooftop solar achieved reductions in grid-supplied kWh of 8% and 37% respectively.
On average reduce customer bills by 19%[3].

5. The IPDRS program has helped Ergon Energy and Energex better understand how to request the specific network support from IPDRS suppliers.

3.4 Evolve

The Evolve project researched, developed and demonstrated a system for coordinating DER in the distribution network to underpin increased network hosting capacity. This was to be achieved by ensuring high penetration DER are able to maximise their connection, operation and participation in markets for energy, ancillary and network services, whilst ensuring the secure technical limits of the electricity distribution networks are not breached.

In simple terms, this involves calculating real and reactive power limits that controllable DER assets must remain within, at different times, to avoid creating voltage breaches or thermal overload issues, and sending these limits to the DER asset controllers. These limits have become widely known in Australia as Dynamic Operating Envelopes (DOEs).



The use of dynamic operating envelopes allows DER to bid into markets for energy and ancillary services without breaching physical or operational limits of electricity distribution networks. In this diagram, green lines correspond to operational monitoring data and network visibility, whilst blue lines correspond to the sequence of actions being demonstrated through the evolve project. DOEs could be used to manage system security constraints but this would require an additional integration with AEMO systems. If operating envelopes were also used to address system security concerns then the operating envelope algorithm would be updated to jointly solve for network voltage and thermal constraints and system security constraints. DER will be sent operating envelopes (Step 1) before separately bidding into AEMO markets (Step 2).

[2] Retrospective baselining is only indicative of the value of HEMS and, in this pilot, conservatives that value.
[3] All primary tariff grid-supplied energy was rated at Ergon Energy Tariff 11 gazetted rates.

3.4.1 Compliance with DMIA Criteria

The project was viewed as meeting DMIA criteria by investigating ways to shift or reduce demand for standard control services through non-network alternatives. The Evolve project includes active management of DER to enable visibility and control of targeted network areas with constraints. The DOEs (outcome of the project) will provide an upper and lower limit for safe operation of the network for both DER import and export that potentially can be used to implement more granular and effective demand management programs to respond to local network constraints.

3.4.2 Nature and Scope

The scope was to calculate the DOEs for DER assets using a variety of low voltage (LV) and medium voltage (MV) network data sources and to include the as-switched network model, as well as the current and forecast operating state. The DOEs will be published to DER aggregators and other interested parties.

3.4.3 Aims and expected outcomes

The Evolve project included development of software systems and installation of additional sensors targeting specific locations to calculate and publish normal-state and emergency operating envelopes and constraints that applied to individual or aggregated DER operating within the selected trial DNSP sites. The project developed capability with calculating and projecting localised envelopes, optimising deployment costs as well as network hosting capacity of DER, while ensuring the secure technical limits of the electricity distribution network are not breached.

3.4.4 The process by which it was selected, including its business case and consideration of any alternatives

The DMIA project approval process was followed for selecting this project (Evolve). Potential DMIA projects are selected and scoped to respond to current and emerging network limitation drivers and adhere to the standard governance framework. Accordingly, once projects are identified and nominated, the eligibility-screening process is performed on nominated projects as a high-level assessment, to determine whether the projects meet the DMIA criteria. Other internal criteria are then assessed – including how the findings of the project, should it be successful, could be applied within the business. Provided all the specified conditions are met, then the project proceeds to the feasibility assessment and approval stages, as per a gated governance framework and with internal subject matter expert review and feedback. Information from the development activities undertaken enables implementation scheduling, milestone planning and confirmation of resources.

3.4.5 How it was/is to be implemented (i.e. general project update)

Initially, working closely with Zepben and the Australian National University (ANU) Battery Storage and Grid Integration Program, Energex and Ergon Energy, along with other Evolve project partners Redback Technologies, Reposit Power and SwitchDIn was mostly involved during the establishment and initial implementation phase, or first half of the Evolve project, providing technical expertise, support and network model data for initial trial areas. For the second half of the project, the Evolve project progressed to further develop and refine its solution alternatively with its other New South Wales (NSW) DNSP partners, Essential Energy, Endeavour Energy and Ausgrid, and also partners the NSW Government, SwitchDIn, Reposit Power and Evergen.

3.4.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

The Evolve project delivered results in the following areas (these were provided by Zepben and ANU, relating to the project findings and learnings for Queensland and NSW DNSPs):

- Research and development into methods of calculating operating envelopes for DER assets using electrical network models and forecasts for load and generation;
- Exploration of techniques to deal with missing and anomalous electrical network model and sensor data;
- A comprehensive report into the benefits that could accrue from the use of DOEs;
- Practical DER hosting capacity calculations; an essential outcome for longer range forecasting and asset investment decisions;
- Knowledge outcomes about data remediation activities to be undertaken to support high penetration DER, accompanying cyber security issues and general challenges with the integration of new technologies needed for the management of DER within the broader Operational Technology (OT) landscape;
- Development and promotion of standards in relation to the modelling of electricity network asset and measurement data, the exchange of these data models, and communications between DERs and DNSPs;
- Co-development and promotion of the Australian Common Smart Inverter Profile (CSIP) standard for DER; and
- The publication of a considerable body of open-source software to support ongoing research and development outcomes.

The significant learnings conclusions from the Evolve project were:

- The use of DOEs could potentially:
  - Increase the hosting capacity of electricity distribution networks by managing solar generation (export) and Electric Vehicle (EV) charging, and Vehicle to Grid (V2G) (both import and export),
  - Help enable DER market participation (both import and export), and
  - Assist with the maintenance of system security.
- For DOE benefits to be realised, the DOEs must be sent to DER assets, and the DER assets must respond. Questions remain as to how this will be accomplished. To do this, the roles and responsibilities of DNSP, aggregators and customer (DER owner) need to be clearly defined.
- DNSP owns and has access to network asset data, and the availability of sensor data for DER connected to the LV network needs to be improved for DOEs to be used effectively. Currently, networks do not have access to interval engineering/power quality data from smart meters. Availability of this data will improve the calculation of DOE for LV networks.

A case study for Evolve Project is available on the Ergon Energy Network website.

3.5 RRCRF Clairview Stanage Project

Ergon Energy recently secured Australian Government funding from the Regional and Remote Communities Reliability Fund (RRCRF) to investigate the feasibility of establishing microgrids at the communities of Clairview and Stanage Bay to improve customer reliability. As part of the funding agreement, Ergon Energy is required to fund a portion of the feasibility study project, which it will do under DMIA.

3.5.1 Compliance with DMIA Criteria

This project looks to identify customer energy usage trends through customer metering and energy audits. Combined with community energy literacy education, customers will have the opportunity to optimise their energy usage and identify potential renewable generation and energy storage technologies that will enable them to manage their load, which in turn reduces the potential impact on the local network in terms of peak and minimum demand.

A key consideration in the development of a microgrid is to understand the customers' load and where there are opportunities for demand management to optimise the design and cost of the microgrid. Microgrids will be a future demand management tool as they will allow load to be moved off the network as a financially viable alternative to investing in traditional network upgrades.

Irrespective of the conclusion of the feasibility study to deploy a microgrid, the demand management learnings will have positive utilisation impacts on the local network. The feasibility of DNSP-led microgrids for grid connected communities has not yet been explored in detail by the business and therefore this project is the first of its kind. The concept of a microgrid is an innovative solution that would potentially utilise controlled renewable generation and energy storage to increase customer reliability and the network's resilience to disturbances, while reducing the need to upgrade existing infrastructure. The aim of the microgrid is to automate seamless switching between the grid and island mode, using smart grid controls to ensure a continuous reliable energy supply, while additionally offering grid support services while in grid connected mode.

3.5.2 Nature and Scope

Establishing microgrids in fringe of grid communities, particularly in remote and challenging environments, will enable Ergon Energy to cost effectively improve or maintain the reliability of supply to customers in these areas and increase community resilience to extreme weather events such as cyclones, flooding and bush fires, that impact the upstream network. Advances in intelligent control systems and reductions in the cost of renewable energy and storage technologies will further enable microgrids to become economically viable compared to traditional network supply from poles and wires. The feasibility study will focus on the Clairview and Stanage Bay townships with community and stakeholder engagement, data acquisition and analysis, microgrid network and economic modelling and simulation of viable and sustainable solutions.

3.5.3 Aims and expected outcomes

The objectives for this project are to:

- Determine the technical and financial feasibility of installing microgrids at the communities of Clairview and Stanage Bay and use the lessons learnt from the feasibility study for other fringe of grid locations;
- Understand customers' energy needs and their interest and willingness to be involved in a future microgrid solution; and
- Develop business intelligence to include deployment of microgrids by Ergon Energy as an option for addressing network constraints such as reliability, power quality or capacity, where viable as an alternative to augmenting the network.

3.5.4 The process by which it was selected, including its business case and consideration of any alternatives

Ergon Energy has selected the townships of Clairview and Stanage Bay as the locations for the microgrid feasibility study. Both communities are supplied by the PD-203 'Northern' 22kV feeder. This feeder is over 1,000km in length and has been consistently identified as one of the "worst performing feeders" in Queensland in terms of the Minimum Service Standards requirements. Clairview is located at the northern-most extremity of this feeder and is supplied from the three-phase network, while Stanage Bay is located at the extremity of a 100km SWER network.

After being award funding (approximately 60% of the total project cost) from the RRCRF, Ergon Energy has created a project which has the balance of required funding sourced from the DMIAM.

3.5.5 How it was/is to be implemented (i.e. general project update)

The project will be delivered through six stages from now until the completion date in April 2024. Each of these stages will be completed with the assistance of the relevant teams and SMEs, with reporting, coordination and management of the project conducted by the Project Manager. This date is a fixed date as it relates to RRCRF funding requirements for feasibility delivery.

The majority of this project will utilise internal skillsets. External work may be required for energy auditing and customer metering installation. When procuring plant and equipment or arranging external work, the relevant network business process and procedures will be followed. To date we have conducted an extensive planning study of the network which supplies Standage Bay and Clairview, including background information, reliability statistics, network protection, identification of network constraints and a high-level technical proposal. We have combined network outage data with customer meter data to provide an in-depth look at network reliability, which will help us determine what solutions, in terms of technology and capacity, would provide maximum benefit against the project outcomes.

Basic microgrid operational control scenarios have been developed and are currently being tested using quasi dynamic simulation modelling techniques. This will provide us with a way to determine how a microgrid might be operated with optimised control schemes and system capacity.

We have taken a no-assumptions approach to our community engagement and invited customers to participate in a quick energy survey which provided us with key insights into what customers care most about when it comes to their supply of electricity. In addition, the project team has visited each of the two communities and talked to residents and business owners about their experience with the power supply and our project.

A project webpage was launched which acts as a landing page for all information regarding the project. A flyer was sent out to each of the customers in the two communities, which detailed the project and included a QR code that links back to the webpage. We are currently in the process of procuring an inverter and energy storage system which we will test in our Microgrid and Isolated Systems Test facility and design/optimise the control strategy and architecture.

3.5.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

A customer study which included detailed energy audits of major customers in the community was completed. This audit not only provided information to the project team regarding the community's energy usage and requirements but was also used to provide energy efficiency tips back to the customers, ultimately helping them to make informed decisions around reducing consumption and saving money on energy bills. To maximise the utilisation of any microgrid technology, such as battery energy storage, network support functionality can be incorporated to potentially address capacity constraints by reducing maximum demand. The customer and community energy study will help inform the potential for this functionality.

3.6 Allawah Fringe of Grid Field Trial

The purpose of this project is to field trial battery energy storage system (BESS) technologies that can reduce the overall demand on the Western Fringe of Grid and SWER by supplementing customer loads and enabling increased value from customer solar PV systems.

3.6.1 Compliance with DMIA Criteria

The storage of customers renewable energy in batteries with a hybrid inverter can be used on problematic fringe of grid locations to reduce the demand and improve power quality on the grid overall and at the customer connection to an acceptable level, to avoid network capital works.

The project is innovative using commercially available BESS technology programmed in a way to support both the customer and the grid.

Traditionally an overload of a fringe of grid location can lead to major works, including:

- upgrading of conductor size
- upgrade of major plant such as SWER isolators
- installation of additional major plant such as MV voltage regulators

If the trial is successful, a deployment of the trialled system in targeted locations could be used to defer, or eliminate the need for, these works. This project is different from the previous DMIA funded project, Grid Utility Support System (GUSS), as that relied on purpose designed and built inverter technology that was connected on the network side of the meter, with limited ability to harness the value of customer owned renewable energy. This concept differs from the other SAPS systems already being trialled, because the SAPS are designed to immediately allow complete disconnection from the grid, and in a different customer segment. This concept instead augments the grid connection in the short term, allowing increased maximum demand to be served whilst reducing the maximum load on the grid. This is achieved with lower upfront capital cost than immediate complete disconnection via a SAPS.

It should be noted that the project is also complementary to the SAPS project and the GUSS project, with its view to integrate system elements that can be used on all three applications into the future – thus providing a more sustainable way of working through consistency in standards, the ability to reduce overall costs by having greater volume in products, reducing the variety of spares to be managed and through consistency in products and form factor, also ensuring a targeted upskilling for the operation, management and maintenance of these systems.

Along with this trial providing an alternative for specific network upgrades noted above, the trial working to align standardised building blocks across the SAPS, Fringe of Grid and GUSS technologies will enable reduced costs for products due to quantity of scale and through consistency of products to be carried as spares, for integration into the Telemetry Hub and in relation to service and maintenance skills.

As part of the project learnings, an estimate to install standardised systems of this type on a more widespread basis will be provided to Network Planning to use as an option to consider when network augmentation is being evaluated.

3.6.2 Nature and Scope

The Western Fringe of Grid refers to extensive SWER and remote powerline networks which are managed by Ergon Energy, mainly constructed in the 1970s and 1980s.

These networks are characterised by long lengths, with some 65,000km (or 40%) of the Qld network comprised of SWER where customer connections are often sparse, and with around 26,000 customers (or 3.5% of the Ergon Energy Network customer base).

These networks are being challenged by a number of issues. Those most relevant to this project are:

- increasing expectation of customers to add renewable energy;
- increasing expectation of customers for increased reliability and power quality;
- increasing load growth beyond original design capacity; and
- proliferation of loads including more sensitive electronic loads and heavy loads such as air-conditioning.

In some specific cases these SWER powerline networks may be removed and replaced by SAPS to meet overall customer needs. More commonly the most economical solution will be to repair and augment the existing grid to cater for increased demand for power, or to correct network deficiencies causing power quality issues. The reconductoring of powerlines, upgrade of major plant such as SWER isolators, or installation of additional major plant such as MV regulators can resolve these issues, but can attract high capital outlay. This project is trialling customer level grid battery storage systems as an alternative method to address grid quality of supply and peak demand issues.

3.6.3 Aims and expected outcomes

This project seeks to demonstrate that a targeted installation of local storage of energy in a battery to reduce maximum demand on the grid can provide a reliable and economical methodology to:

- Increase the maximum demand (kW) available to a customer without causing peak demand or power quality issues;
- Provide a demand reduction alternative in grid augmentation scenarios;
- Improve power quality by limiting the export of generated solar photo voltaic (PV) by storing and using the energy onsite; and
- Reduce system losses.

A customer hosting these local energy storage systems can also receive the following side benefits:

- Provide some level of redundancy during grid outage; and
- A power bill reduction where excess PV reduces the bill instead of being exported at a lower tariff.

3.6.4 The process by which it was selected, including its business case and consideration of any alternatives

Under the previous Western Fringe of Grid project, testing in the lab was done to prove the consistency, reliability and functionality of a several devices including battery inverters, HEMS and LV regulators.

From this testing two devices were recommended to be used in field trials as the next step to confirm their suitability for wider application in the network, the SP PRO and the LVR-30.

The SP PRO is a BESS inverter with advanced functionality and reliability, which is what will be trialled in the Allawah project. (The LVR-30 is a voltage regulator which will not be required for this site.)

During lab testing the SP PRO inverter proved its ability to provide:

- Reliable maximum demand limiting;
- Off grid backup power; and
- Consistent performance with a supplier that provides excellent support.

Maximum demand limitation is one major objective of the field trial project. The BESS inverter can be set up to provide power from the battery when the customers load exceeds a certain threshold. The main source of power for the battery is PV. In the event of reduced PV generation the battery is topped up at low load times at night if needed. A DMIA business case was submitted with a 2-year timeframe to install, monitor and learn from the system in the field.

3.6.5 How it was/is to be implemented (i.e. general project update)

An external contractor will construct a cubicle/s containing the inverters, ~20kWh battery bank and communications equipment. The cubicle will be installed at the Allawah Retreat in Tolga, North Queensland. This site has been chosen as a friendly site with people with good understanding of the technology (and its challenges). The location is ideal as it has good mobile coverage, extreme summer temperatures, is on a spur line and is still relatively close to Cairns, where Ergon Energy staff are located. We have had monitoring installed at this site for more than a year so we also understand the energy usage variability on site.

The system, network and customer will be monitored for 12 to 18 months and the effectiveness of the system throughout various seasons and weather patterns will be evaluated. Learnings along the way will be used to improve the system parameters including export thresholds, battery state of charge targets, grid battery top-up schedules, and other parameters. The project will also provide learnings for development of standardised battery and inverter products.

Whilst the BESS will be physically installed on the customer side of the meter, the trial will explore the pros and cons of both customer side and network side connection.

Whilst examining the customer side connection scenario, direct control of the customers solar PV and possibly some loads by the system will be enabled via communication link.

A contract has been awarded to design, construct and install the BESS external cubicle enclosure.

The design is advanced with construction to commence in August 2022.

3.6.6 Any identifiable benefits that have arisen from it, including any off peak or peak demand reductions

Learnings about the layout for a BESS system which is suitable for outdoor deployment including:

- Cubicle design withstanding heat and passively dissipating heat as much as possible;

- Keeping the cubicle layout as compact as possible;
- Beginning the journey of standardisation of such cubicles for widespread replication; and
- Developing the import, export and load support system settings to maximise use of renewables minimise grid load.