Industry Engagement Document

Ergon Energy Network and Energex

December 2023

Part of Energy Queensland

Contents

1. Introduction

This Ergon Energy Network and Energex Industry Engagement Document (IED) describes how we engage and work with customers and demand management (DM) providers to develop and implement demand side, non-network, and Stand-Alone Power System (SAPS) solutions, to address distribution system limitations and provide lower costs for customers.

The document provides information on:

- how to be informed about non-network or applicable SAPS opportunities
- how we identify limitations and assess non-network or SAPS solutions
- submitting proposals for a non-network or SAPS solution
- how we assess proposals for non-network or SAPS solutions
- how we pay for non-network or SAPS solutions

It is relevant to Ergon Energy Network and Energex as distributed network services providers (DNSPs) and satisfies National Electricity Rules regulatory requirements (see Appendix A).

For more information about Ergon Energy Network and Energex, and our parent company Energy Queensland, see Appendix B and C.

1.1 Non-network or SAPS solutions

Under our distribution authorities, we are required to ensure we meet reliability and performance standards and have sufficient capacity to meet electricity demand. When it is efficient to do so, we use non-network or SAPS solutions to match customer demand and electricity supply to provide alternative and complementary solutions to network centric infrastructure.

Non-network and SAPS solutions, also known as DM solutions, are methods of addressing network limitations or system demand that don't involve expanding the network. Whenever we identify a network limitation, we consider DM solutions in addition to the preferred network option.

Investing in DM solutions can offer credible alternatives to network infrastructure, leading to lower costs while still maintaining network reliability. We actively seek innovative DM solutions that support our efforts to manage demand, maintain system reliability, defer network costs and meet Queensland's target of net zero emissions by 2050.

Over the short term, demand management helps to maintain system reliability; over the longer term, demand management can defer network expansion.

Demand management solutions can include:

- direct load control
- distributed generation (including standby generation, embedded customer generation and co-generation)
- demand response
- energy efficiency
- fuel substitution
- interruptible loads
- load shifting
- power factor correction
- pricing/tariffs
- reactive/voltage support batteries paired with embedded customer generation
- micro grids
- energy storage (batteries)
- dynamic connections
- aggregated energy management
- Stand-Alone Power Systems (SAPS)

1.2 Industry Engagement Document

This Industry Engagement Document guides our engagement with customers and DM service providers to address any limitations on our distribution networks. It describes how we seek and assess proposals for DM solutions.

Our strategic objectives are to:

- improve industry engagement and the screening of DM solutions in the distribution planning process
- improve the ways we identify network limitations and provide details about them to customers and DM providers, using consistent, clear terminology
- provide adequate time, support, and mechanisms for stakeholders to engage, respond and participate in DM solutions
- identify, investigate and implement commercially sound DM solutions while engaging with customers, stakeholders and DM providers as per our approach outlined in the Ergon Energy Network and Energex Demand Management Plan
- deliver on DM solutions that prevent, reduce, or delay the need for network investment

2. How to be informed about our non-network and SAP opportunities

We ensure that customers and DM providers have access to accurate and up-to-date information about identified network limitations and non-network opportunities, or where applicable SAPS opportunities may exist. We seek to provide opportunities for proactive and effective engagement with customers and DM suppliers to submit general expressions of interest, request for proposals and DM solutions.

Our industry engagement includes:

- a dedicated Demand and Energy Management and Engineering Team to support enquiries and applications for DM solutions, including SAPS.
- publishing consultation documents for network limitations where we're seeking DM solutions. These are published on the Ergon Energy Network and Energex website via the following formats:
  - Request For Proposals (RFPs)
  - Options Screening Reports (OSRs)
  - Draft Project Assessment Reports (DPARs)
  - Final Project Assessment Reports (FPARs)
- providing incentive maps (where relevant) that identify target areas for network limitations and provide a price signal for DM solutions.
- maintaining an Industry Engagement Register (IER) of parties interested in receiving our consultation documents and other various news regarding demand and energy management and SAPS across our networks. More information about our IER is included in Appendix D

All enquiries about demand side activities can be directed to our Demand and Energy Management Team:

Energex
Email: demandmanagement@energex.com.au

Ergon Energy Network
Email: demandmanagement@ergon.com.au

3. Identifying network needs and assessing demand management solutions

We identify network needs through a clearly defined annual planning process designed to identify network limitations and operational constraints based on network forecasts. Each year, we publish a Distribution Annual Planning Report (DAPR) to summarise our planning process.

The latest DAPR and supporting information for Ergon Energy Network and Energex are available on our Ergon Energy Network DAPR and Energex's DAPR.

Our processes for identifying network limitations and assessing DM solutions will vary, depending on the type, time, cost and size of the network limitation.

The general assessment processes we use are described in the figures below: Figure 1 describes our assessment process for projects with expenditure below $6 million; Figure 2 describes our assessment process for projects with expenditure above $6 million.

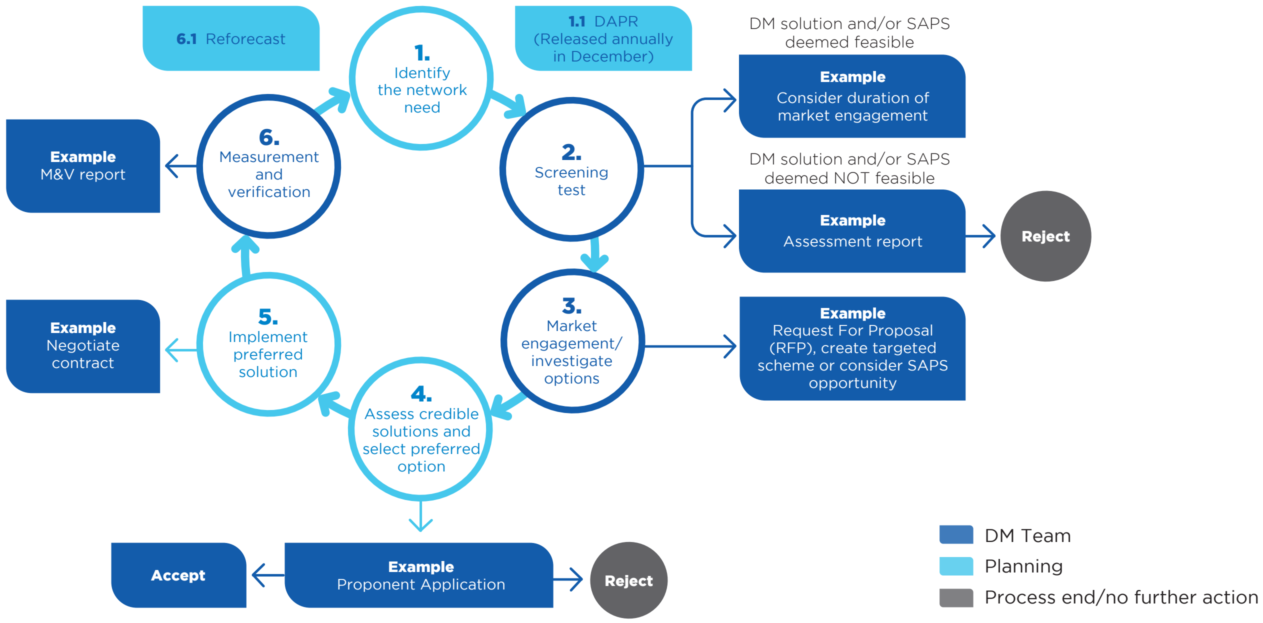


Figure 1. Non-Network Assessment Process for expenditure <$6M

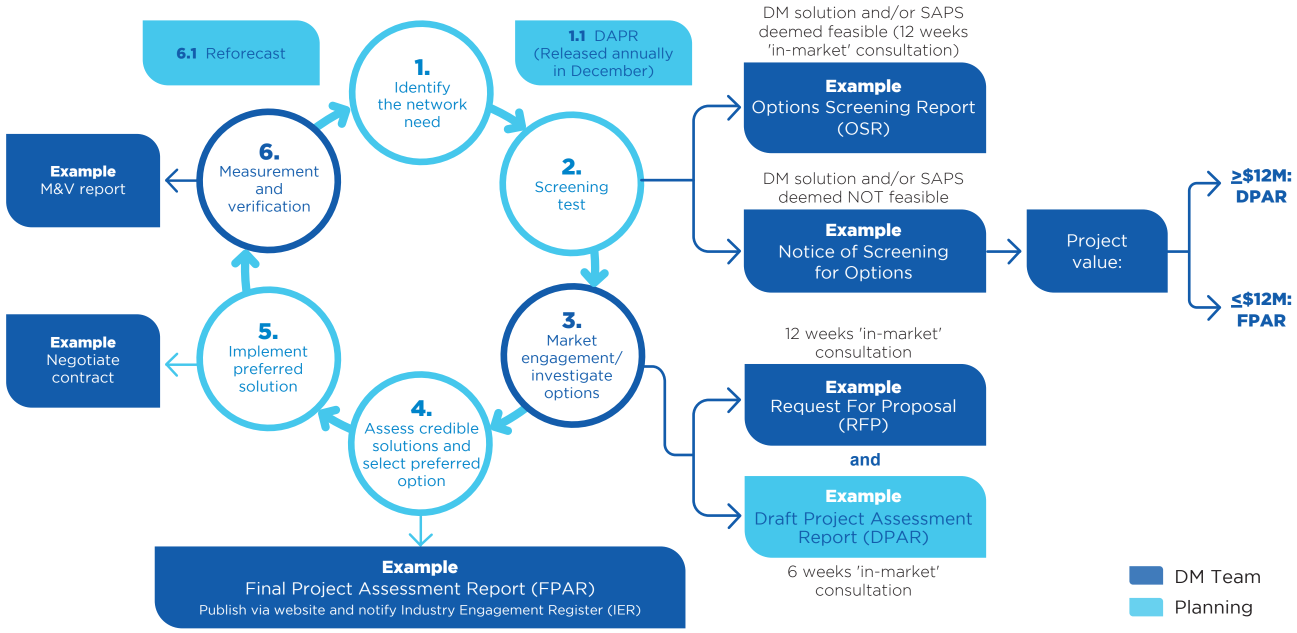


Figure 2. Non-Network Assessment Process for expenditure >$6M (RIT-D)

4. Screening for non-network or SAPS opportunities

Our screening tests are designed to test whether the proposed DM solution or SAPS is a credible option for the identified network limitation.

Our screening tests include a desktop study to:

- compare non-network or where applicable SAPS options and network solutions for each constraint.
- consider estimated commercial costs, including net present value (NPV) and estimated project deferral value.
- consider impending limitations (identified by the planning team using relevant security standards), load forecasts, load profiles, project timing and load at risk.
- compare the proposal with past non-network projects.
- consider input from service providers and customers.

The desktop study is designed to determine whether the non-network solution is likely to secure load reductions and/or network deferral.

5. Market engagement

When a screening test concludes that a non-network or SAPS option may be effective, we conduct market and/or direct customer engagement. At this stage, we consider a range of possible demand management solutions, or may stipulate specific solutions.

Our engagement depends on the project's forecast expenditure and size, and the timing of the network constraint being addressed. We consider DM solutions that wholly or partly reduce the network limitation and we may deem a partial solution to be credible.

5.1 Request for proposals

Where the forecast capital expenditure for the most expensive credible option is less than $6 million, we develop opportunities for credible non-network solutions or SAPS by gauging the interest and ability of DM service providers and customers.

Depending on the specific requirements of the limitation, we may publish details online (using maps) or invite solutions through an RFP. Small or time-limited constraints may have a short period of market consultation (1–3 months), while long-term constraints may be addressed through an incentive scheme and left open to ongoing market engagement and participation.

We publish information on our website detailing the location, problem statement and value on offer. We also provide this information to our IER through periodic email notifications.

Spotlight: An RFP published for the 2023–24 distribution feeder network limitations for Ergon Energy Network

In February 2023, we published an RFP seeking demand response and DM solutions to help manage network constraints during the 2023–24 summer peak demand period in various target areas of the Ergon Energy Network. Submissions closed in October 2023. The RFP identified 36 target areas in the Ergon Energy Network where DM solutions could address limitations in capacity, reliability and/or voltage.

The RFP is available on the Ergon Energy Network website.

Ergon Energy Network

We are seeking demand response or non-network solutions to help us manage network constraints and/or limitations in the following target areas. The specifics of the identified need may vary slightly for each target area and related feeder. Greater detail can be provided on request.

Target Area	Feeder	Target Area	Feeder
Mackay Northern Beaches	Bucasia	**Burdell**	Black River 14
Mackay Northern Beaches	Rosewood Dr	**Burdell**	Bohle No.03
Mackay Northern Beaches	Eimeo	**Burdell**	Bohle No.08
Mackay Northern Beaches	Blacks Beach	**Bargara**	Riverview
Mackay Northern Beaches	Rural View	**Bargara**	Bargara
Mackay Northern Beaches	Chenoweth	**Bargara**	Kelly's Creek
Mackay Northern Beaches	Beaconsfield Rd	**Susan River**	Susan River
Mackay Northern Beaches	Celeber Dr	**Hervey Bay**	Doolong South
Mackay Northern Beaches	Bedford Rd	**Hervey Bay**	Tooth St
Moranbah	Township No.1	**Toowoomba Region**	Harlaxton
Moranbah	Township No.2	**Toowoomba Region**	Peace St
Moranbah	Township No.3	**Toowoomba Region**	Granada
Moranbah	Township No.4	**Toowoomba Region**	Kratzke
Moranbah	Town No.5	**Toowoomba Region**	Cabarlah
Moranbah	Town No.6	**Edmonton**	Hambledon
Kirwan	Dan Gleeson No.07	**Bentley Park**	Hardy Rd
Kirwan	Dan Gleeson No.10	**Edmonton, Mt Peter**	Mt Peter Rd
Cannonvale	Abel Rd	**Ingham**	Ingham No.08

Details of the network support requirements are as follows (note, these may vary slightly for each target area and related feeder):

- **Network Support Period:** 1 November 2023 – 31 March 2024
- **Demand Response Required:** Minimum 500kVA demand response / network support per network event request (measured and verified). Additional kVA will be considered.
- **Duration of Network Support Event:** Up to 6 hours duration (i.e., 3pm – 9pm)
- **Number of Network Support Events Required:** Up to 10 network support events during the nominated network support period
- **Energy at Risk & Value:** Supplied upon application
- **Load Duration Curves:** Supplied upon application
- **Affected Classes of Customers**: Supplied upon application
- **Initial Preferred Option**: No initial preferred option has been identified
- **Value:** Between $20/kVA - $100/kVA per annum. **NOTE:** Value is dependent on the selected target area and deferral benefit of associated capital project cost.
- **Closing date:** 31 October 2023

Non-network solutions could comprise one or a combination of embedded generation or battery storage systems, call-off load, load shift or other demand-side load management solutions. **Please note**, limitation timing requirements specify that existing 'Brownfield' solutions are preferred, as 'Greenfield' solutions are considered unlikely to be deployed and operational for the upcoming Network Support Period.

Applications and/or enquiries for information that will enable you to provide an informed response, should be directed to demandmanagement@ergon.com.au. For your security, we do not transmit sensitive information via email.

Provide feedback

We are always looking for ways to better engage with businesses and customers. If you have feedback that may help us to improve the Regulatory Test and Request for Proposal Consultations process, or how we can better engage industry in general, please email us at demandmanagement@ergon.com.au or demandmanagement@energex.com.au.

5.2 Regulatory Investment Tests – Distribution

Where the total capital expenditure (including augmentation and replacement expenditure) of the most expensive credible option is greater than $6 million, we conduct a regulatory investment test for distribution (RIT-D). The RIT-D process is prescribed under Chapter 5 of the National Electricity Rules.

We publish a Options Screening Report (OSR) to seek information from interested parties about possible solutions to address the need for investment. The OSR is published on our website and sent by email to our IER.

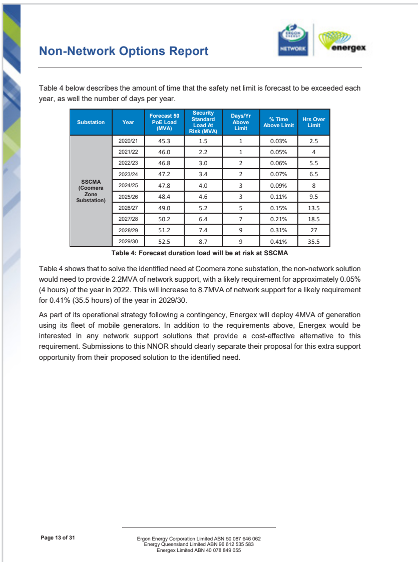
Spotlight: RIT-D process and screening report for the Coomera-Pimpama network limitation

The Coomera-Pimpama network limitation involves an identified security standard load at risk (MVA) limitation at Coomera Zone Substation on the Energex network. The identified network solution to solve this limitation has been valued at $12.93 million. Each year the network solution is deferred is worth $388,000 in NPV savings. A third-party provider tendered a credible commercial battery solution in response to our consultation for this project. The battery solution satisfied the security standard load at risk (MVA) and is cheaper than the $388,000 per annum deferral benefit. We are, therefore, pursuing this option.

For more information about this project, see the Screening Report for the Coomera-Pimpama Network Limitation

RIT-D and RFP information for Ergon Energy Network and Energex is available via our websites:

- **Ergon Energy Network:** Regulatory Investment Test for Distribution projects
- **Energex:** Regulatory Investment Test for Distribution projects



Non-Network Options Report

Table 4 below describes the amount of time that the safety net limit is forecast to be exceeded each year, as well the number of days per year.

Substation	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days/Yr Above Limit	% Time Above Limit	Hrs Over Limit
SSCMA (Coomera Zone Substation)	2020/21	45.3	1.5	1	0.03%	2.5
	2021/22	46.0	2.2	1	0.05%	4
	2022/23	46.8	3.0	2	0.06%	5.5
	2023/24	47.2	3.4	2	0.07%	6.5
	2024/25	47.8	4.0	3	0.09%	8
	2025/26	48.4	4.6	3	0.11%	9.5
	2026/27	49.0	5.2	5	0.15%	13.5
	2027/28	50.2	6.4	7	0.21%	18.5
	2028/29	51.2	7.4	9	0.31%	27
	2029/30	52.5	8.7	9	0.41%	35.5

Table 4: Forecast duration load will be at risk at SSCMA

Table 4 shows that to solve the identified need at Coomera zone substation, the non-network solution would need to provide 2.2MVA of network support, with a likely requirement for approximately 0.05% (4 hours) of the year in 2022. This will increase to 8.7MVA of network support for a likely requirement for 0.41% (35.5 hours) of the year in 2029/30.

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this NNOR should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

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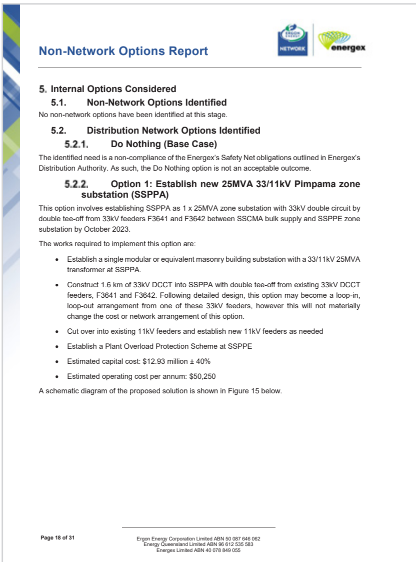
Energy Queensland Limited ABN 96 612 535 583
Energex Limited ABN 40 078 849 055



Non-Network Options Report

5. Internal Options Considered

5.1. Non-Network Options Identified

No non-network options have been identified at this stage.

5.2. Distribution Network Options Identified

5.2.1. Do Nothing (Base Case)

The identified need is a non-compliance of the Energex's Safety Net obligations outlined in Energex's Distribution Authority. As such, the Do Nothing option is not an acceptable outcome.

5.2.2. Option 1: Establish new 25MVA 33/11kV Pimpama zone substation (SSPPA)

This option involves establishing SSPPA as 1 x 25MVA zone substation with 33kV double circuit by double tee-off from 33kV feeders F3641 and F3642 between SSCMA bulk supply and SSPPE zone substation by October 2023.

The works required to implement this option are:

- Establish a single modular or equivalent masonry building substation with a 33/11kV 25MVA transformer at SSPPA.
- Construct 1.6 km of 33kV DCCT into SSPPA with double tee-off from existing 33kV DCCT feeders, F3641 and F3642. Following detailed design, this option may become a loop-in, loop-out arrangement from one of these 33kV feeders, however this will not materially change the cost or network arrangement of this option.
- Cut over into existing 11kV feeders and establish new 11kV feeders as needed
- Establish a Plant Overload Protection Scheme at SSPPE
- Estimated capital cost: $12.93 million ± 40%
- Estimated operating cost per annum: $50,250

A schematic diagram of the proposed solution is shown in Figure 15 below.

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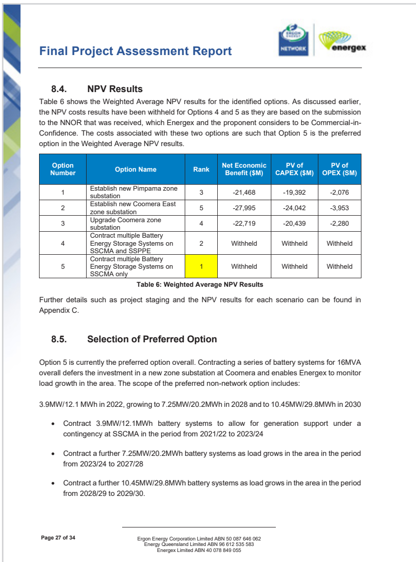

Final Project Assessment Report

8.4. NPV Results

Table 6 shows the Weighted Average NPV results for the identified options. As discussed earlier, the NPV costs results have been withheld for Options 4 and 5 as they are based on the submission to the NNOR that was received, which Energex and the proponent considers to be Commercial-in-Confidence. The costs associated with these two options are such that Option 5 is the preferred option in the Weighted Average NPV results.

Option Number	Option Name	Rank	Net Economic Benefit ($M)	PV of CAPEX ($M)	PV of OPEX (SM)
1	Establish new Pimpama zone substation	3	-21,468	-19,392	-2,076
2	Establish new Coomera East zone substation	5	-27,995	-24,042	-3,953
3	Upgrade Coomera zone substation	4	-22,719	-20,439	-2,280
4	Contract multiple Battery Energy Storage Systems on SSCMA and SSPPE	2	Withheld	Withheld	Withheld
5	Contract multiple Battery Energy Storage Systems on SSCMA only	1	Withheld	Withheld	Withheld

Table 6: Weighted Average NPV Results

Further details such as project staging and the NPV results for each scenario can be found in Appendix C.

8.5. Selection of Preferred Option

Option 5 is currently the preferred option overall. Contracting a series of battery systems for 16MVA overall defers the investment in a new zone substation at Coomera and enables Energex to monitor load growth in the area. The scope of the preferred non-network option includes:

3.9MW/12.1 MWh in 2022, growing to 7.25MW/20.2MWh in 2028 and to 10.45MW/29.8MWh in 2030

- Contract 3.9MW/12.1MWh battery systems to allow for generation support under a contingency at SSCMA in the period from 2021/22 to 2023/24
- Contract a further 7.25MW/20.2MWh battery systems as load grows in the area in the period from 2023/24 to 2027/28
- Contract a further 10.45MW/29.8MWh battery systems as load grows in the area in the period from 2028/29 to 2029/30.

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6. Submitting proposals for DM solutions

We encourage customers and DM providers to submit proposals for DM solutions – either in response to a request from us, in response to an identified opportunity, or if the DM provider considers their proposal to offer value to the network.

Depending on the project, applications for DM solutions should include:

- customer site information
- proposed project details
- required hardware
- a reasonable estimate of costs (+/- 40%), including incentive payments
- timeframe for delivery
- details about the proponent submitting the proposal (including any experience with similar projects)
- a description of the proposed demand management product and how it services the network limitation (either partially or in full)
- the time, duration and output of load (kVA per year) expected to be managed (this may address minimum or maximum load)
- relevant technical information (such as capacity of generators, dispatch details and proposed connection points)
- development status (if applicable)
- identified market benefits and a clear methodology used to calculate those benefits
- evidence the proponent has customer authorisation to recover bill/data/site information from the DNSP
- any other relevant information

In some cases, we may request specific details that respond to criteria relevant to the identified network limitation. Our Demand and Energy Management Team are available to provide further information and advice.

Proposals for non-network solutions can be submitted by email:

- **Ergon Energy Network:** demandmanagement@ergon.com.au
- **Energex:** demandmanagement@energex.com.au

An example of a best practice non-network submission is included in Appendix E.

7. Assessing credible options

We assess DM solutions when they are sufficiently developed to be commercially and technically feasible in addressing an identified network limitation. We assess proposed solutions according to four mandatory criteria:

1. ability of the proposed solution to meet the technical requirements for addressing the identified network limitation, or part of the network limitation
2. ability of the proponent to deliver the solution in sufficient time to meet the identified need
3. ability of the DM solution outcomes to be measured and verified
4. commercial outcomes, costs, market benefits (where applicable) and risks of the solution compared with other options (i.e. NPV outcomes).

We do not wish to limit a potential proponent's ability to innovate. However, unproven, experimental, or undemonstrated technologies are unlikely to be considered as feasible options to address an identified limitation.

For RIT-D situations, we publish the outcomes in draft and/or final project assessment reports whether the DM solutions are found to be viable or not. For smaller projects not subject to a RIT-D, we publish the outcomes in a way that suits the size, timing and cost for the project.

While a proposal is being assessed, we keep proponents informed about its progress at agreed intervals.

Appendix F includes an example of a non-network assessment.

8. How we pay for non-network or SAPS solutions

Our payments for DM solutions and SAPS are negotiated for each project, based on the type of DM solution offered and the value of any deferred network costs. In most instances and for current incentive schemes, we cap payments at an allocated maximum $/kVA or establish a fixed-price contract.

9. Implementing the DM solution

When a DM solution is chosen to address a network limitation, we begin a procurement process to implement the solution. Through the procurement process, we negotiate terms and contracts to ensure both probity and prudent purchasing practice. The negotiation of cost, time and quality in contractual terms will vary depending on the network risk, size, cost, location, and availability of non-network solutions.

10. Measurement and verification

We apply best practice and cost-effective measurement and verification processes to determine the demand response achieved by DM solutions. We use measurement and verification to ensure the energy and/or demand savings meet the contract terms and reporting requirements.

11. Connection agreements with embedded generators

We encourage customers and demand management providers to submit applications for embedded generators via our online application process. The online application enables us to assess and negotiate connection agreements and consider the requirements for setting charges, terms, and conditions. Note: terms may impact the cost of delivery for DM solutions, and it is advisable to submit a connection agreement application or preliminary application at the earliest opportunity.

Relevant conditions might include customer site information, tariff class, proposed project details, connection type, generation size, export requirements, cost, completion time and any specified generation authorities.

More information about connection agreements and lodging applications, and the contact details for our Connection Team are available online at:

- **Ergon Energy Network:** Connections
- **Energex:** Connections

12. Avoided customer transmission use of system (TUOS) charges

We are required to calculate avoided charges for the locational component of prescribed transmission use of system (TUOS) services for embedded generators.

We do this by:

1. determining the prescribed designated pricing proposal charges (DPPC) payable by Ergon Energy Network or Energex without the embedded generator injecting energy into the network
2. crediting the difference of its actual DPPC payable back to the embedded generator's account.

More information about the methodology we use to calculate avoided TUOS payments for eligible embedded generators is available in our online network tariff guides at:

- **Ergon Energy Network:** Network tariffs & pricing
- **Energex:** Network tariffs & pricing

13. Appendices

Appendix A: Industry Engagement Document compliance with National Electricity Rules

Clause	Industry Engagement Document Requirement	Section Reference
a	A description of how the Distribution Network Service Provider will investigate, develop, assess and report on potential non-network options and (in relation to a SAPS enabled network) potential SAPS options.	3, 4 and 7
b	A description of the Distribution Network Service Provider's process to engage and consult with potential non-network/demand management providers to determine their level of interest and ability to participate in the development process for potential non-network options or where applicable, potential SAPS options.	2, 5 and 6
c	An outline of the process followed by the Distribution Network Service Provider when negotiating with non-network/demand management providers to further develop a potential non-network option or SAPS option.	5, 6 and 7
d	An outline of the information a non-network provider is to include in a non-network or DNSP-led SAPS proposal, including, where possible, an example of a best practice non-network proposal.	6 and Appendix E
e	An outline of the criteria that will be applied by the Distribution Network Service Provider in evaluating non-network or DNSP-led SAPS proposals.	7 and Appendix F
f	An outline of the principles that the Distribution Network Service Provider considers in developing the payment levels for non-network options or (where applicable) SAPS options.	8
g	A reference to any applicable incentive payment schemes for the implementation of non-network options or SAPS options and whether any specific criteria is applied by the Distribution Network Service Provider in its application and assessment of the scheme.	2, 5 and 8
h	The methodology to be used for determining avoided Customer TUOS charges, in accordance with clauses 5.4AA and 5.5.	12
i	A summary of the factors the Distribution Network Service Provider takes into account when negotiating connection agreements with Embedded Generators.	11
j	The process used, and a summary of any specific regulatory requirements, for setting charges and the terms and conditions of connection agreements for embedded generating units.	11
k	The process for lodging an application to connect for an embedded generating unit and the factors taken into account by the Distribution Network Service Provider when assessing such applications.	11
l	Worked examples to support the description of how the Distribution Network Service Provider will assess potential non-network or SAPS options in accordance with paragraph (a).	Appendix F
m	A hyperlink to any relevant, publicly available information produced by the Distribution Network Service Provider.	1.2, 2, 3, 5.1, 5.2, 6, 11 and 12
n	A description of how parties may be listed on the Industry Engagement register.	Appendix D
o	The Distribution Network Service Provider's contact details.	2

Table 1. Demonstrated compliance with schedule 5.9 of the NER

Appendix B: About Energy Queensland

Energy Queensland Limited (Energy Queensland) is a Queensland Government Owned Corporation that operates businesses providing energy services across Queensland, including:

- two distribution network service providers (DNSPs) – Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon Energy)
- a regional service delivery retailer – Ergon Energy Queensland Pty Ltd (Ergon Energy Retail)
- an affiliated contestable business – Yurika Pty Ltd (Yurika), which includes Metering Dynamics Pty Ltd (Metering Dynamics).

Appendix C: Our network

8,200 employees

39 isolated communities

1.7 million power poles

969MVA Total large-scale solar PV systems connected

800,000 solar energy systems connected

4,133MVA capacity of small-scale solar PV systems

3 network control centres

2.3 million connected customers

36,600GWh electricity distributed (a year)

5,221MW Energex network-wide peak maximum demand

237MW Energex network-wide minimum demand

2,637MW Ergon Energy Network network-wide peak maximum demand

799MW Ergon Energy Network network-wide minimum demand

24,471 Electric vehicles registered#

8,966 Battery installations

Source: *Energy Queensland Annual Report 2022-23*

Excluding electric motorcycles.

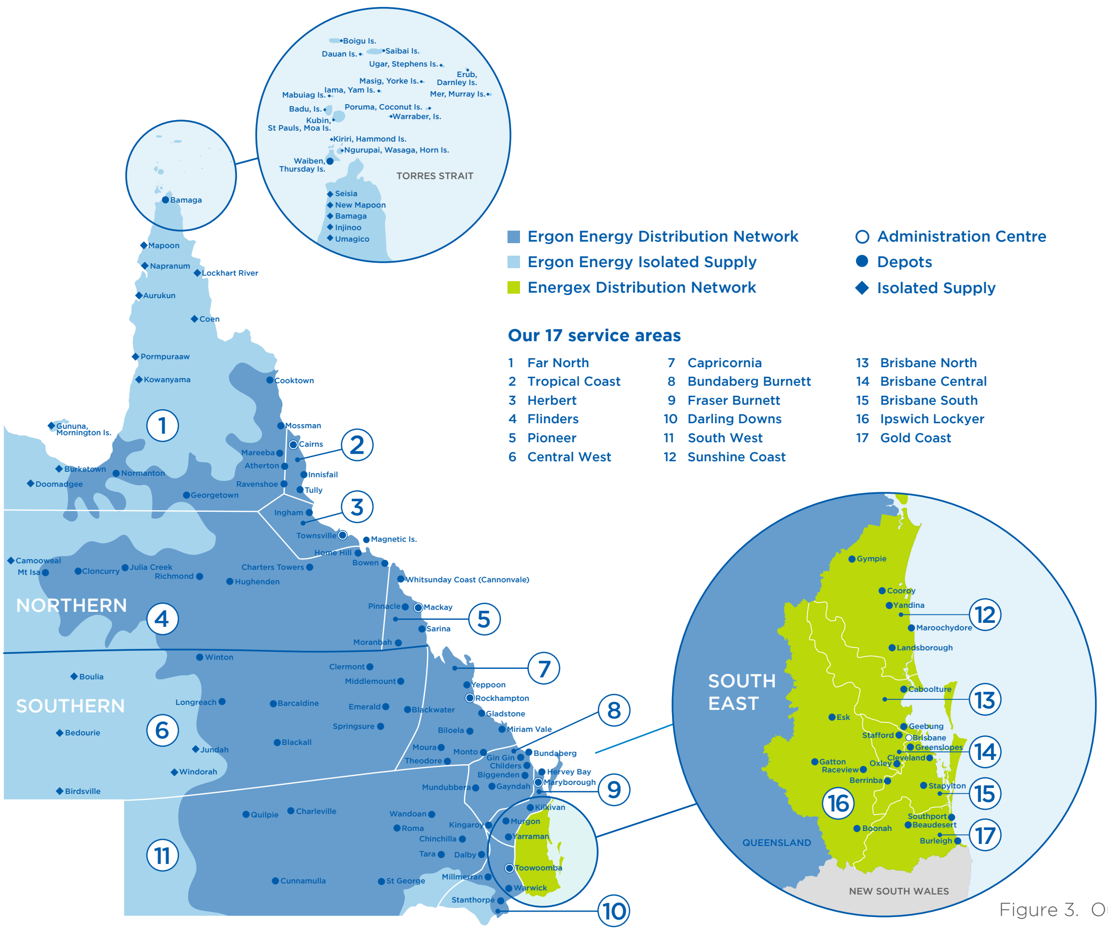


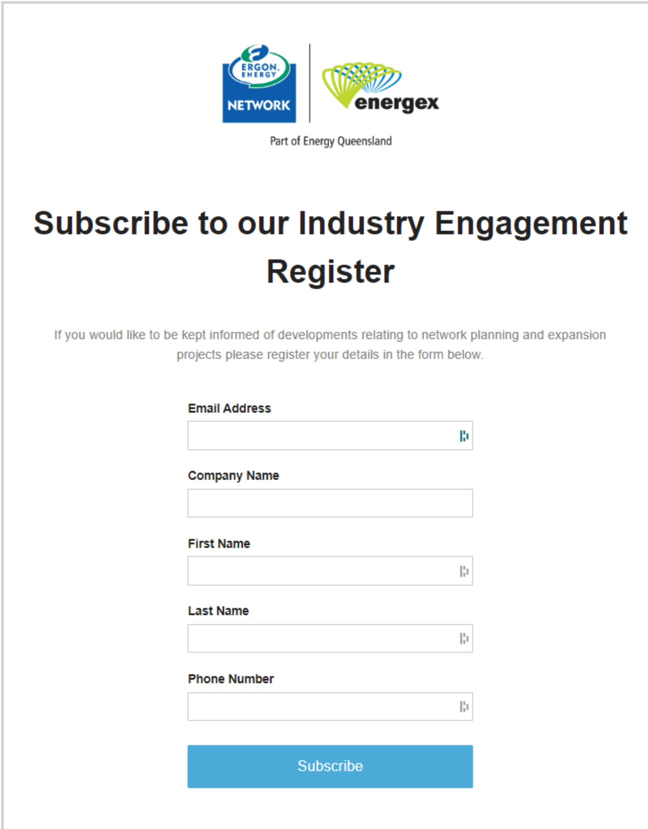
Figure 3. Our network and service area

Appendix D: Industry Engagement Register

We maintain an Industry Engagement Register (IER) of customers, demand management providers, private companies, government departments, and individuals interested in keeping up to date with demand side opportunities. We distribute information to IER subscribers about network planning, expansion projects, non-network initiatives and consultation opportunities.

To be informed about Energex and Ergon Energy Network's Industry Engagement opportunities, Requests for Proposals (RFP), Regulatory Investment Test for Distribution (RIT-D) and Stand-alone Power Systems (SAPS) register for Energex's Industry Engagement Register and Ergon's Industry Engagement Register.

Industry Engagement Register Example:



Part of Energy Queensland

Subscribe to our Industry Engagement Register

If you would like to be kept informed of developments relating to network planning and expansion projects please register your details in the form below.

Email Address

Company Name

First Name

Last Name

Phone Number

Subscribe

Appendix E: Example best practice non-network proposal

Energex Project:	Date: 10/06/2022
Upgrade A Bulk Supply Substation	
Non-network Provider (Proponent) Details:	
Company:	Company name supplied
Contact Name:	Name supplied
Phone:	Phone number supplied
Email:	Contact email supplied
ABN:	ABN supplied
Customer Details (if applicable):	
Name:	Customer name supplied
Supplied Address:	Address supplied
ABN:	ABN supplied
NMI:	NMI supplied
Technical Details:	
Demand Management Product:	Load Curtailment
Site Peak Demand:	8MVA
Site Operation Times:	24 hours per day, 7 days per week
Load Curtailment Available:	2MVA per production line (3x production lines available). Total 6MVA
Load Curtailment Duration:	Up to 12 hours
Maximum Dispatch Events:	8 per annum
Annual Load Curtailment Available:	48MVA per annum
Summary:	The customer has a total peak demand of approximately 8MVA and runs four production lines for up to 24 hours per day for seven days per week. Each production line has a demand of greater than 2MVA. The customer can curtail load with a 20-minute notification period for up to 12 hours. Up to three production lines can be curtailed at any one time. The maximum number of dispatches per annum is eight. This matches seasonal requirements as prescribed by the DNSP.
Cost Estimate:	
Availability fee:	$ x per kVA per annum (+/-20%)
Dispatch fee:	$ x per kVA per dispatch (+/-20%)
Customer Authorisation:	
Customer Authorisation:	Signed letter of authorisation supplied

Note: Before submitting a non-network proposal, please consider these questions:

- Does your solution adequately address the network limitation kVA/MVA load support requirements?
- Is your solution equal to or cheaper than the annual network deferral benefit (or NPV)?
- Have you submitted a preliminary connection enquiry or considered network connection agreement fees and tariff arrangements in your DM solution proposal?

Appendix F: Example non-network assessment

Ergon Energy Network Project:

Network Limitation – Feeder 'X'.

For a non-network option to be considered a credible option it must:

- address the identified need
- be technically and commercially feasible (e.g. cost below defined value)
- be implemented in sufficient time to meet the identified need
- rank a NPV rating.

In this example, a non-network option to deploy energy efficiency (EE) measures (see Non-network option 1), failed to meet technical requirements to address the identified need for the network limitation on Feeder 'X'. The load reductions possible from the EE measures (1MVA) were insufficient to address the load at risk corresponding to the network limitation (6MVA) and therefore was not applicable for further evaluation. All other options were considered credible and so were submitted to be ranked according to their economic benefit or net present value (NPV).

Note: In some scenarios it may be possible that a combination of the EE measures in conjunction with a network solution presents a feasible technical solution. If this is the case, then further evaluation is considered.

	Meets technical requirements	Ability to deliver and timing	Ability of solution to be measured and verified	NPV ranking
Network option 1: Upgrade feeder	✓	✓	N/A	2
Network option 2: Install transformer	✓	✓	N/A	3
Non-network option 1: Energy efficiency measures	✗	N/A	N/A	N/A
Non-network option 2: Customer load curtailment	✓	✓	✓	1

Table 1. Assessment of options to solve a network limitation

In the example above, the option presenting the highest net economic benefit is the preferred option: Non-network option 2 – customer load curtailment

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