Demand Side Engagement Strategy

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1. About Ergon Energy

Ergon Energy Corporation Limited, operating under the newly formed parent company Energy Queensland Limited, supplies electricity across 97% of the state of Queensland servicing over 740,000 homes and businesses. This service area of more than 1.7 million square kilometres includes the expanding coastal and rural population centre’s to remote communities of outback Queensland and the Torres Strait.

Our electricity network consists of approximately 160,000 kilometres of powerlines and one million power poles, along with a range of associated infrastructure such as major substations and power transformers. We also own and operate 33 stand-alone power stations that provide supply to isolated communities across Queensland, which are not connected to the main electricity grid.

Over recent years demand on our network has changed dramatically, due to factors such as economic slowdown, solar energy penetration and the awareness and take up of energy efficiency behaviours and new, more energy efficient appliances. Due to the radial nature of our network, however, we still need to respond to pockets of localised growth. We also need to respond to an evolving energy challenge, as discussed in our Demand and Energy Management Plan.
2. Purpose of this document

This document constitutes Ergon Energy’s Demand Side Engagement Strategy (DSES) as required by clause 5.13.1 of the National Electricity Rules (NER). This document communicates Ergon Energy’s approach and the associated processes for engaging with stakeholders, customers and non-network providers on the supply of demand side solutions as an alternative to investing in network infrastructure, either through the formal Regulatory Investment Test for Distribution (RIT-D) or other means depending on the requirement.

Ergon Energy’s strategy is to encourage market led provision of demand side options to building electricity network infrastructure through a mix of:

- demand response; a temporary ‘call’ to respond to a peak in demand (bringing embedded customer generation plant online or taking customer load off line);
- demand management; a permanent shift in customer load away from peak periods;
- the use of network embedded generation, energy storage, modular sub stations, reviewing risk tolerances and/or contingency planning; and
- the utilisation of the network in areas and/or times where spare capacity is available (encourage additional kWh).

In accordance with the NER, this document outlines the following:

**Table 1: Schedule 5.9 of the NER – DSES Specific Requirements**

<table>
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<th>NER Requirement</th>
<th>DSES Section</th>
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<td>A reference to any applicable incentive payment schemes for the implementation of non-network options and whether any specific criteria is applied by Ergon Energy in its application and assessment of the scheme</td>
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3. **Non Network Alternative (NNA) Processes**

This section describes how Ergon Energy investigates, develops, assesses and reports on potential non-network options to address network constraints or power quality issues. Figure 1 shows the high level process for considering NNA options.

![NNA Implementation Process Diagram](image)

**Figure 1:** Ergon Energy's non-network solution implementation process

Initially, network risks are identified and classified as constraints, where there is an identified network investment, or risks where the investment is likely to occur in the medium term but is not yet defined.

A risk location is valued utilising our Optimal Incremental Pricing (OIP) methodology and enables us to activate a low cost program early in the risk cycle. This risk based NNA program can operate in an area until the risk is mitigated or until the risk reaches a point where there is an identified constraint.

Constraint areas of the network are where the OIP NNA process has not been able to mitigate the risk and there is an identified need to invest in network infrastructure. The constraint area requires the application of a RIT-D when the proposed investment is expected to exceed $5 million.

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1 A non-network option is any means by which an identified need can be fully or partly addressed other than by a network option.
In addition to calling for Requests for Information (RFI) for solutions for the problem area, Ergon Energy’s planning group employs a screening process to *investigate* whether an NNA option exists. Screening examines factors such as the size of the investment required, the amount of capacity that needs to be provided in order to economically defer building network assets, the number and type of customers in that area of the network, the success of previous customer focussed demand management programs and any other factors such as the life and condition of the existing asset. If screening identifies the area is suitable for a possible NNA asset deferral response, Ergon Energy *develops* an NNA proposal utilising existing knowledge on factors such as:

- the availability of customer embedded generation;
- any opportunities for power factor correction;
- customer demographics and the types of demand management options available in that area of the network; and
- the cost and expected take up rate and the expected demand reduction.

In addition, the network risks and NNA performance are reviewed annually to ensure that risk has not changed and that any NNA solution is providing value.

If the Ergon Energy NNA solution proposed, or the solution proposed by another provider through the RFI process, is *assessed* to be more prudent and efficient than investing in network at that time, then this solution is applied and scheduling of any required network solutions is adjusted accordingly. *Assessment* of NNA options occurs in the development of a business case to address the network constraint and is based on maximising the Net Present Value (NPV), taking into account the costs associated with the NNA and network options.

In order to engage the market as early as possible all upcoming NNA projects are:

- dynamically updated on the internet via our [Network Incentive Map](#) (formerly known as the Demand Management Incentive Map) which shows an up to date view of Ergon Energy’s current and future incentive program, see Section 10;
- *reported* in Ergon Energy’s annual [Demand and Energy Management Plan](#) (DMP)² to the Queensland Government, Department of Energy and Water Supply (DEWS) which is available on our website, see Section 10; and
- reported annually via Ergon Energy’s [Demand Management Outcomes](#) report (DMP Outcomes Report) to DEWS, also available on our website, see Section 10.

Ergon Energy follows the RIT-D process to *engage and consult* with potential non-network providers to determine their level of interest and ability to participate in the development process for potential non-network options where the network investment is over $5 million.

### 3.1. Screening for NNA options

Ergon Energy has developed and implemented an NNA Process to ensure there is robust assessment of network and non-network alternatives in areas of impending network limitations. The process determines how NNA decisions are made and implemented within Ergon Energy and was developed to support RIT-D compliance under the NER.

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² Clause 127(1) of Electricity Amendment Regulation (No. 1) 2009
The Development and Approval component of this process is detailed in Appendix A of this DSES and covers the development of an overall portfolio of network investments where these investments are systematically screened for NNA solutions.

The process integrates the screening requirements of the proposed RIT-D with Ergon Energy's planning and program management processes. It provides greater scope in terms of the viability of potential cost effective solutions and increased assurance of regulatory compliance and prudent investment. The steps undertaken as part of the RIT-D are detailed in Appendix A. This includes the development, design and delivery of an individual NNA project or a program.

As part of our RIT-D process the market is notified of the opportunity to provide NNA solutions through RFIs issued by Ergon Energy.

Planning reports prepared for proposed network augmentations form the basis for RFI documents which specify the drivers of the investment need. RFIs are published on the Ergon Energy website for public consultation with a date specified when responses and proposals are required to be received.

Results of the RFI are then published once the RFIs have been received and analysed.

Depending on the outcome, project type and size, NNA proponents may be invited to contract with Ergon Energy directly or participate in a closed tender process.

A worked example of a RIT-D can be found on our website which consists of:

- Constraint identification report
- Non-network option report
- Final project assessment report

It is also possible to receive RIT-D updates by registering on our portal, see Section 9.
4. **Principles for developing payment levels for non-network options**

This section describes the principles for developing payment levels for non-network options.

Valuing the non-network solution is dependent on the network risk and timing of that risk. An early intervention in the risk cycle enables lower cost procurement of NNA solutions and allows for a level of risk in the procurement process. Therefore, we have developed a risk-based valuation technique that enables future network risk to be ‘priced’ early in the risk cycle.

Whilst still in its infancy, Ergon Energy’s new OIP methodology has the benefit of learning algorithms that allow the ‘price’ to be revised on an annual basis starting at the lowest cost offers, aligned to a future network risk. The algorithms look at the existing network capacity and the forecast network load growth, as well as any past and future demand and energy management activities. This allows the risk valuation to change based on an ongoing program’s success or failure, so, by its very design, corrects the ‘price’ against under or over performance or due to changes in external market conditions.

By moving early with an offer, based on this methodology, we can better align with when a customer is in the market for a new product, such as an air conditioner and potentially incentivise a demand management solution at a much lower cost than if we were trying to incentivise the solution at a later date after they had already purchased.

This also applies to any non-financial programs or incentives we offer to address network risks associated with building design – encouraging the right solutions is most cost-effective for all at the planning stage.

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**Figure 2: Optimal Incremental Pricing methodology**

By pricing the risk early, we can offer the market low-cost incentives that could support purchasing decisions that are optimal for the network, and help us deliver for customers overall for the best possible price. Rather than waiting until we have to actively seek demand-side solutions to defer an investment.
If the risk continues to grow and a constraint is identified we apply a more traditional approach of valuing the network option. When the network is considered constrained and a network investment is proposed, there is an assessment phase whereby the cost of the non-network option is compared to a network option. As the comparison is done on the basis of maximising the NPV, the value of an NNA solution will vary according to when the network investment is scheduled. If the investment is over $5 million, a RIT-D will be instigated as per the Australian Energy Regulator’s (AER) RIT-D and associated application guidelines.

A major component of the development of network risk and consequently the value of demand is an assessment of how much load is potentially at risk at any point in time, and the risk associated with that each year. Figure 3 shows that the energy at risk in a system is not as simple as looking at the rating of the system, the risk of failure and the maximum load on the system. In a section of the network where the load is very peaky (where there is a low load factor), as illustrated in Figure 3, the maximum demand only exists for a short period of time each year. If a failure occurs during the peak period, there is energy at risk. However, given peak demand only occurs for a short period of time, it is more likely that a failure will occur when the load is lower and by the time maximum demand occurs, the failure will have been mitigated or corrected. Determination of this chance of failure is a probabilistic calculation based on the network construction and load profiles which impacts the value of demand and the likelihood of initiating a demand management program in that area.

Figure 3: How the load duration curve affects energy at risk

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\[ \text{Energy at risk} = (\text{load} - \text{value above N-1}) \times \text{each half hour = energy kWh}. \]
5. Access to incentives for NNA solutions

Ergon Energy has a dedicated web page for our active programs where there is an incentive payment scheme available for the implementation of non-network options – see the Network Incentive Map. As the programs and criteria vary year to year dependent on the network risk, network load profile, customer demographics and other criteria, our programs will be updated with information on our incentives web page, and searchable via the interactive Network Incentive Map.

As a general rule Ergon Energy has programs that suit both commercial and residential customers and have a range of standard products and offerings which may be available depending on the active program.

In recent years Ergon Energy has invested in a Demand Response Management System to enable better control, tracking, reporting and interfacing to demand side resources. One of the main benefits of this system is the use of open protocols, such as OpenADR (Open Automated Demand Response), for communicating to devices over the internet. This enables low cost, simple access for customer participation in our demand side programs.

Some examples of products offered by Ergon Energy to its customers are discussed below.

5.2. Demand response incentives

5.2.1. Customer Call ON Generation (COG)

Customers with generators onsite for backup purposes can be paid an annual and/or event based incentive payments for a limited number of years to provide standby generation in the case of a contingency event at the identified network constraint (typically local zone substation). Ergon Energy may pay these customers directly or pay an aggregator to manage the COG.

5.2.2. Criteria for COG (Customer Embedded)

The following criteria apply:

- An incentive can only be claimed for demand reduction within areas highlighted by Ergon Energy on our incentives web page.
- The price paid for incentives will be the price listed on the web page and agreed at the time contracted.
- The customer's generator must take full load within 30 minutes or less of being called.
- The customer must be able to reduce the site demand on call across peak times of day for up to seven days if and when required during the nominated months.

The process for connecting embedded generation is detailed in Section 7.

5.2.3. Customer Call OFF Load (COL)

Customers with integrated control systems, such as Building Management Systems (BMS) or irrigation and automated pumping systems, can move energy consumption outside the peak period, or reduce or stop non-essential processes for temporary periods (e.g. air conditioning), to reduce their demand during peak times. Ergon Energy may pay these customers directly for COL or pay an aggregator to manage the COL on behalf of a number of customers.
Criteria for COL >250kVA

- Demand reduction during the peak times must be >250kVA.
- The customer must reduce demand by the agreed value within 30 minutes or less, of being called.
- The Customer must be able to reduce the site demand on call across peak times of day for up to seven days if and when required during the nominated months.

Criteria for COL >50kVA and <250kVA

- Demand reduction during the peak times must be between 50kVA and 250kVA.
- The customer must reduce demand by the agreed value within two minutes or less of being called.
- The customers load will be automatically controlled via BMS, PLC (Programmable Logic Controller) or similar.
- Demand reduction can be managed across a number of sites by an aggregator.
- The customer must be able to reduce the site demand on call across peak times of day for up to seven days if and when required during the nominated months.

5.3. Reduced demand incentives for small to medium businesses

Ergon Energy’s demand management incentives programs for small to medium businesses recognise that each business is different and measures to reduce demand during peak times will vary. For this sector, a $/kVA is published and customers or their supplier / installer are permitted to propose one or more demand management measures from a wide range of possible measures. The application process requires customers to outline the business as usual network demand, and the proposed post installation network demand profile. Once the network demand reduction is agreed with Ergon Energy, including any measurement and verification requirements, a Letter of Offer is issued to the customer. Typical measures supported through this approach include power factor correction, improvements / changes to lighting, heating ventilation and air-conditioning (HVAC), pumps and motors, water heating, building management and controls.

5.3.1. Deemed incentives for small to medium business and residential customers

For smaller business customers, the cost involved in accessing the type of incentives listed previously is potentially prohibitive and would outweigh the value of any demand reduced. Ergon Energy recognises that in constrained areas (nominated through our website), these customers also have a role to play in reducing demand. We have developed a process to deem kVA reduction from replacing older, higher demand products, such as lighting and air-conditioning, with new, more efficient and lower demand equipment. As each demand management project is slightly different, deemed products which are valid for an incentive will be detailed on a project by project basis. Customers meeting the nominated criteria can redeem incentive payments online at the program incentive page (see example) of or by written application.
6. **Information to be provided as part of an NNA proposal**

An NNA RIT-D proposal should contain the following information:

- details of the party making the submission (or proposing the option);
- details of the party responsible for the providing the option (if different to the proponent);
- an explanation of the relevance of the proposal and/or options presented;
- technical details of the project (capacity, reliability, availability, proposed connection point if relevant, etc.) to allow an assessment of the likely impact on supply capability;
- if applicable to the option being offered the:
  - size, type and location of load(s) that can be reduced, shifted, substituted or interrupted
  - size, type and location of generators that can be installed or utilised if required
  - type and location of action or technology proposed to reduce peak demand or provide electricity system support;
- sufficient information to allow the costs of the option to be incorporated in a cost effectiveness comparison in accordance with AER’s RIT-D;
- information about the impact on the proposal if electricity demand were to be 25% above/below Ergon Energy’s forecasts;
- an assessment of the ability of the proposed option to meet the technical requirements of the NER;
- timing for availability of the option, and whether it is a committed project;
- the level of payment required to fund the proposal (initial payment, availability payment, dispatch payment, etc.) in both total dollars and/or $/kVA; and
- other material that would be relevant in the assessment of the proposed option.

A worked example of a RIT-D can be found on our website and consists of:

- Constraint identification report
- Non-network option report
- Final project assessment report

6.1. **Evaluation criteria**

Responses and proposals to the RFI are collated and assessed internally by a panel of subject matter experts to determine their suitability. Proposals are typically assessed on (but not limited to) the following criteria (Table 2).
Table 2: Ergon Energy’s criteria for assessing RFI responses

<table>
<thead>
<tr>
<th>DESCRIPTION</th>
<th>WEIGHTING (%)</th>
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</thead>
<tbody>
<tr>
<td>Mandatory Prerequisites</td>
<td>PASS/Fail</td>
</tr>
<tr>
<td>Scope &amp; Technical Validity</td>
<td>15%</td>
</tr>
<tr>
<td>Financial and management capability</td>
<td>10%</td>
</tr>
<tr>
<td>Experience and corporate culture</td>
<td>15%</td>
</tr>
<tr>
<td>Network compatibility / customer &amp; stakeholder impacts</td>
<td>25%</td>
</tr>
</tbody>
</table>

### 6.2. Negotiation

Ergon Energy employs a risk based procurement process for negotiating and developing potential non-network solutions. The negotiation of cost, time and quality contractual terms will vary depending on the network risk, location and the available non-network solutions.

### 6.3. How Ergon Energy is engaging with the market

Ergon Energy is committed to fostering a strong market to provide prudent and efficient solutions to network problems. This requires Ergon Energy to form a deeper engagement with product and service providers of NNA solutions. Any provider of NNA services or customer can apply to Ergon Energy for incentives, providing they meet the specified criteria.

In addition to advertising opportunities to the market through the Network Incentive Map and through RFIs, Ergon Energy has two other platforms to engage with and provide information to market providers of NNA solutions. These platforms have been created to foster stronger communications with market providers.

- Preferred Consultancy/Contractor Panel for specialist services in demand management – the panel is a pre-qualified procurement panel which Ergon Energy utilises for Ergon Energy commissioned NNA solutions and related services such as energy audits; and
- Ergon Energy’s partnership program, the Trade Ally Network (TAN).

#### 6.3.1. Preferred Consultancy/Contractor Panel

The panel is a preferred supplier list to provide pre-qualified specialist resources for the identification, development and implementation of Ergon Energy commissioned NNA solutions (where the Ergon Energy NNA solution is considered the most prudent and efficient compared to other proposed internal and external solutions). Appointment to the panel is ongoing with periodic reviews of panel members.

#### 6.3.2. Ergon Energy’s TAN

Ergon Energy has created the TAN to provide Ergon Energy customers access to a network of accredited providers of energy efficiency and demand management products and services. Ergon Energy recognises that these types of businesses are already providing these and related services to customers and, by working with TAN members, Ergon Energy can broaden the depth and breadth of engagement with customers to increase our ability to reduce demand.
In areas selected for NNA solutions, Ergon Energy will actively refer customers to TAN members who can then assist them to implement demand reduction solutions and to access incentive payments. To help in this process the TAN is provided information and education on the latest incentives available across the network, via a regular Energy Services e-newsletter.

Examples of the criteria that businesses must meet to become members of the TAN are detailed on Our partnership program website, see Section 10.

It is important to note that access to incentive payments is NOT restricted to TAN members or their clients.
7. **Customer Embedded Generation**

The term ‘Embedded Generator’ is quite broad and can be broken down into three main categories:

- generating units installed in a counterparty's premises that are isolated from Ergon Energy's network. In this case, Ergon Energy does not enter into any contracts with the counterparty in respect of such generating units; although Ergon Energy may want to negotiate a network support agreement (see Section 3);
- generating units installed in a counterparty's premises that are electrically interconnected with Ergon Energy's network but do not export electricity into Ergon Energy's network (where Ergon Energy normally enters into a ‘parallel generation consent agreement’); and
- generating units installed in a counterparty's premises that are electrically interconnected with Ergon Energy's network and which export electricity into Ergon Energy's network (either intermittently or consistently) (where Ergon Energy normally enters into a connection agreement that permits the export of electricity).

Larger embedded generators that meet the definition of an ‘Embedded Generator’ under Ergon Energy's pricing proposal are considered to be ‘Major Customers’. In addition to these, Ergon Energy also has grid connected micro-embedded generators that convert renewable energy into electricity. These are mostly solar inverter energy system (IES) connections. These embedded generator customers are generally considered to be small customers.⁴

7.1. **Non-exporting embedded generating systems 30 kVA and above**

Non-exporting embedded generating systems are those which we do not permit to export their excess electricity to our distribution network.

A non-exporting embedded generation system can include connection via an IES installation with a renewable energy source, such as solar panels, or via a rotating machine installation, such as diesel generators.

It can assist in the event of emergency outages, supply interruptions or, to help manage a customer's demand on our network during peak energy use times.

If a customer wishes to submit an application to connect a non-export embedded generating system, the form *Application to Connect Non Export Embedded Generation Unit* must be completed and be accompanied by the documentation listed in the form.

These applications are often made by a customer’s system retailer or installer, but as the electricity account holder, the customer will still need to give their consent.

The *Standard for Connection of Embedded Generators in the Ergon Energy Distribution Network* outlines the requirements for embedded synchronous generators and inverter-based systems (exporting or non-exporting) with a total nameplate rating of up to, but not exceeding, 5,000 kW at a single connection point. It also provides information about a customer's rights and obligations when connecting to, and interfacing with, our network.

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⁴ Customers who consume less than 100MWh per annum
7.2. Exporting 30 kVA - 5,000 kW

This process aligns with Chapter 5 of the NER and applies to all embedded generator proponents whose generating systems benefit from the standing exemption from registration with Australian Energy Market Operator (AEMO) (which generally applies to generating systems up to 5,000 kW).

Further information on the process to connect is available in Embedded Generation Information Pack. Customers will need to complete these documents:

- Export Embedded Generation Enquiry Form 30kW to 5MW ; and
- Export Embedded Generation Application Form 30 kW to 5MW.

The Standard for Connection of Embedded Generators outlines the requirements for embedded synchronous generators and inverter-based systems with a total nameplate rating of up to, but not exceeding, 5,000 kW at a single connection point. It also provides information about a customer’s rights and obligations when connecting to, and interfacing with, our network.

7.3. Exporting 5,000 kW and above

This process aligns with Chapter 5 of the NER and applies to:

- All embedded generator proponents whose generating systems do not benefit from the standing exemption from registration with AEMO (which generally applies to generating systems up to 5,000 kW); and
- Generating systems under 5,000 kW where the proponent has elected to be processed under Chapter 5.

Further information on the process to connect is available in the Embedded Generation Information Pack. Customers will need to complete these documents:

- Export Embedded Generation Enquiry Form greater than 5MW; and
- Export Embedded Generation Application Form.

7.3.1. Important information

Anyone who intends to operate more than 30 MW of generation capacity and connect it to a distribution or transmission network in Queensland must first hold a generation authority or special approval. This authority is issued by the Department of Energy and Water Supply (DEWS).

A failure to hold such an authorisation is an offence under the Electricity Act 1994 (Qld).

If a customer proposes to operate more than 30 MW of generation capacity at a site and connect it to a network, we strongly suggest that the customer contacts DEWS early in the planning process. This will allow for the application to be made to the Director General, considered and approved before the proposed connection. The process can typically take four months from application.

7.4. Model connection agreements

To establish or modify a generation connection to our distribution system, we require customers to enter into a Negotiated Connection Establishment Contract (we refer to this as the ‘Construction Contract’). This Construction Contract sets out the works that both parties will need to perform for the connection.
In addition, due to the nature of the facility, we expect that the customer will also enter into a separate Negotiated Ongoing Connection Contract (we refer to this as the ‘Connection Agreement’). This governs the ongoing connection of the facility to our distribution system after the completion of the works (rather than rely upon the Deemed Standard Connection Contract that applies by default under legislation).

For more details and model agreements please see our large scale renewables and generation web page.
8. **Avoided Customer TUOS**

Clause 5.5(h) of the NER requires Distribution Network Service Providers (DNSPs) to calculate avoided charges for the locational component of prescribed TUOS services, and clause 5.5(i) requires DNSPs to calculate the amount to be passed through to an Embedded Generator. This is done by determining the:

- charges for the locational component of prescribed TUOS services that would have been payable by the DNSP for the relevant financial year “if the Embedded Generator had not injected any energy at its connection point during that financial year”;

- amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the DNSP, which amount will be the relevant amount for the purposes of paragraph (h) [clause 5.5(h)].

Avoided TUOS payments are made by Ergon Energy to Embedded Generators who have:

- sought access to Ergon Energy’s distribution network under clause 5.5 of the NER;
- a generator Connection Agreement with Ergon Energy that includes a relevant Avoided TUOS payment clause;
- registered as a Generator Rules Participant.

Following the end of the relevant financial year, Ergon Energy will make the Avoided TUOS payment in the form agreed with the Embedded Generator. The methodology that Ergon Energy uses to calculate Avoided TUOS payments to comply with clause 5.5 of the NER is set out in our Information Guide for Standard Control Services Pricing and summarised below.

**Step 1.** Determine the amount of energy sent out by the Embedded Generator in the relevant financial year (kWh);

**Step 2.** Convert this to an equivalent amount of energy at the Transmission Network Connection Point (TNCP) by adjusting the export energy by the Distribution Loss Factor of the Embedded Generator;

**Step 3.** Determine the net generator output (i.e. the generator output that is utilised by the local distribution network by subtracting the actual metered energy that flows back into the transmission network at the TNCP);

**Step 4.** Add the net generation output to the TNCP actual metered data for the financial year;

**Step 5.** Determine the TUOS that would have been charged if the Embedded Generator was not connected, by recalculating the customer TUOS usage charges (demand and energy);

**Step 6.** Subtract the actual TUOS payment from the amount calculated in step 5; and

**Step 7.** Arrange payment of the resultant value from step 6 to the Embedded Generator.

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5 NER, clause 5.5(i)(1)(i)
6 NER, clause 5.5(i)(2)
9. Demand side engagement register

Ergon Energy’s demand side engagement register is managed through our RIT-D partner portal. Interested parties may subscribe at any time to receive updates on the RIT-D (see section 10 for web links to the portal).

Additionally, Ergon Energy has a TAN group of companies that receives information about our demand management program and are searchable by customers on our website. It is free to register on the TAN and can be done so by filling out a form on our web page, see Section 10 for the web links.
10. Useful links

The following links and contact details are provided to further facilitate review of Ergon Energy’s demand side programs.

- The Network Incentive Map and a list of all the areas where we are currently seeking non-network solutions:

- The RIT-D web page, including links to register in our portal to be automatically updated on RIT-D changes:

- A worked example of a RIT-D can be found on our website, which consists of:
  - Constraint identification report
  - Non-network option report
  - Final project assessment report

- General information on the network and network investment plans:

- Information on demand management including plans and reports:

- Generation connection:

- Small scale generation connections:

- Information on the portal for the demand side engagement register:

- Portal registration page for the demand side engagement register:

- TAN registration and information page:
11. Contact details

The following contact details can be used to contact Ergon Energy.

All RIT-D processes are now managed via our RIT-D portal. Interested parties must register to receive regular updates.

Portal:


Registration:


TAN and general demand management:

Email: demandmanagement@ergon.com.au
Ph: 1300 550 766

General contact information is included on our website:


Ergon Energy Network enquiries: 13 74 66 (7.00am - 6.30pm Monday to Friday)
International enquires: +61 7 3069 4100
Email general enquiries: customerservice@ergon.com.au

Mail address:

Ergon Energy
PO Box 1090
Townsville QLD 4810
Appendix A. Screening for NNA options

Ergon Energy has developed and implemented a NNA process to ensure there is robust assessment of network and non-network alternatives in areas of impending network limitations. The process determines how NNA decisions are made and implemented within Ergon Energy and was developed to support RIT-D compliance under the NER and is detailed below.