



UE PL 2202 Demand Side Engagement Document

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APPROVAL AND AMENDMENT RECORD

Document № UE PL 2202 – Demand Side Engagement Document

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VERSION	AMENDMENT OVERVIEW
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1 Overview

This Demand Side Engagement Document (**DSED**) has been prepared by United Energy (**UE**) as required under clause 5.13.1(e) to (j) of the National Electricity Rules (**NER**).

The purpose of this document is to present UE's demand side engagement strategy outlining UE's process for engaging and consulting with non-network service providers, and for investigating, developing, assessing and reporting on non-network options as alternatives to network projects, under the National Distribution Planning and Expansion Framework.

The information included in this document is in accordance with schedule 5.9 of the NER. More specifically, the DSED:

- Provides an overview of UE's planning framework and approach to engage non-network service providers for addressing network capacity limitations identified in UE's Distribution Annual Planning Report (**DAPR**).
- Describes how UE will maintain its Demand Side Engagement Register for parties wishing to be advised of relevant publications and events relating to UE's planning activities.
- Provides an outline of technical data requirements expected from non-network service providers when responding to a Regulatory Investment Test for Distribution (**RIT-D**) consultation, and minimum criteria that non-network options should meet.
- Describes the method adopted by UE to assess non-network options and negotiate services proposed by non-network service providers.
- Describes the method used to determine the applicable non-network incentive payments.
- Provides real examples of UE's non-network engagement, consistent with this DSED.

2 Introduction

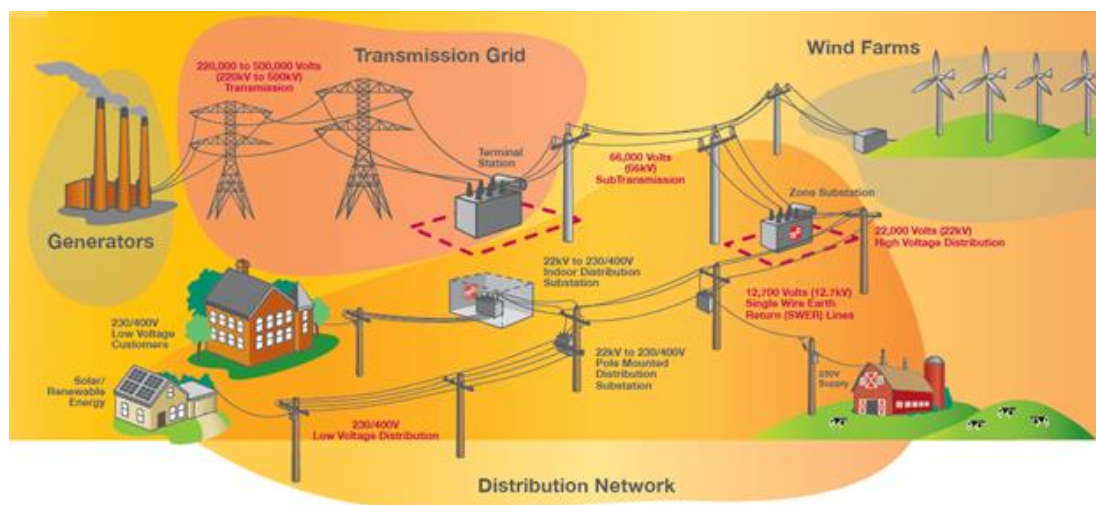
This chapter sets out background information on UE and how it fits into the electricity supply chain.

2.1 WHO WE ARE

UE is a regulated Distribution Network Service Provider (**DNSP**) within Victoria. UE owns the poles and wires which supply electricity to homes and businesses.

A high level picture of the electricity supply chain is shown in the diagram below.

Figure 1: The electricity supply chain



The distribution of electricity is one of four main stages in the supply of electricity to customers. The four main stages are:

- **Generation:** generation companies produce electricity from sources such as coal, wind or sun, and then compete to sell it in the wholesale National Electricity Market (**NEM**). The market is overseen by the Australian Energy Market Operator (**AEMO**), through the co-ordination of the interconnected electricity systems of Victoria, New South Wales, South Australia, Queensland, Tasmania and the Australian Capital Territory.
- **Transmission:** the transmission network transports electricity from generators at high voltage to five Victorian distribution networks. Victoria's transmission network also connects with the grids of New South Wales, Tasmania and South Australia.
- **Distribution:** distributors such as CitiPower, Powercor and UE convert electricity from the transmission network into lower voltages and deliver it to Victorian homes and businesses. The major focus of distribution companies is developing and maintaining their networks to ensure a reliable supply of electricity is delivered to customers to the required quality of supply standards.
- **Retail:** the retail sector of the electricity market sells electricity and manages customer accounts. Retail companies issue customers' electricity bills, a portion of which includes regulated tariffs payable to transmission and distribution companies for transporting electricity along their respective networks.

2.2 THE FIVE VICTORIAN DISTRIBUTORS

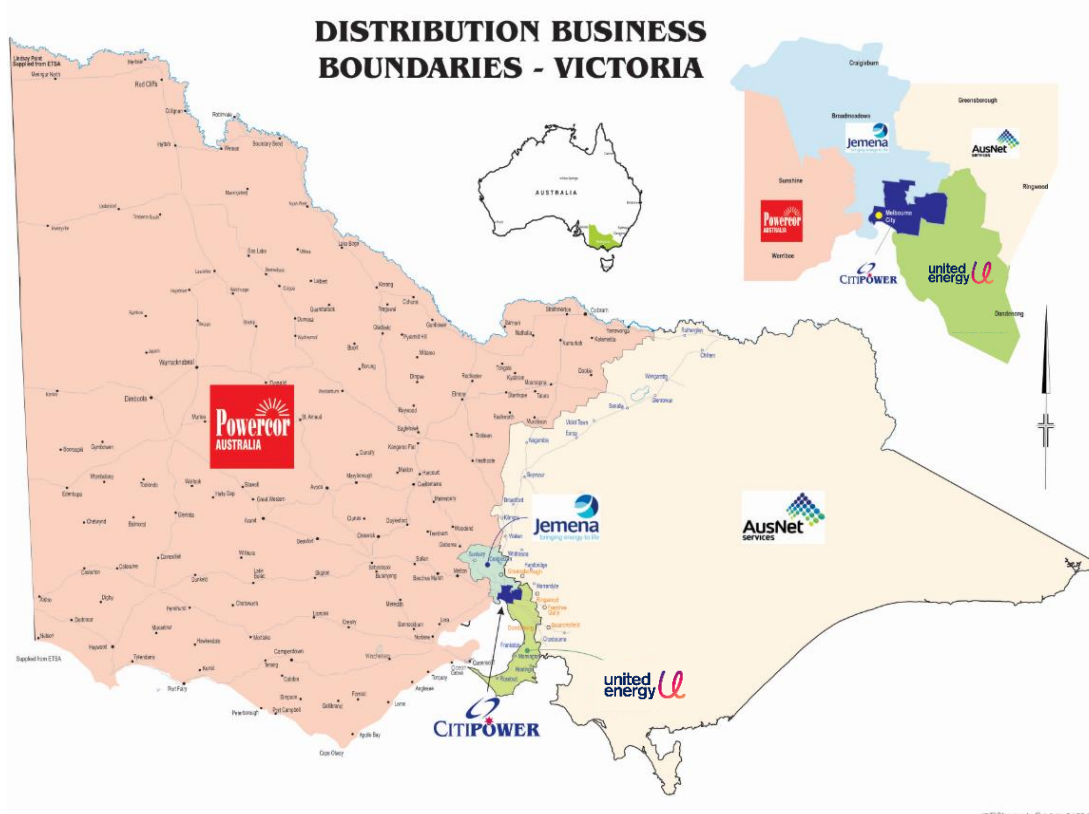
In the distribution stage of the supply chain, there are five businesses operating in Victoria. Each business owns and operates the electricity distribution network. UE is one of those distribution businesses.

The UE network provides electricity to customers in Melbourne's south east and the Mornington Peninsula. UE's service area is largely urban and semi-rural, and although geographically small (about one percent of Victoria's land area), it accounts for around one-quarter of Victoria's population and one-fifth of Victoria's electricity maximum demand. In particular, the service area consists of the:

- northern part which is a leafy developed urban area in metropolitan Melbourne, bounded by the AusNet Electricity Services and CitiPower service areas and Port Phillip Bay. The area includes predominantly residential and commercial centres such as Box Hill, Caulfield, Doncaster and Glen Waverley, and light industrial centres such as Braeside, Clayton, Heatherton, Mulgrave and Scoresby;
- central part is a mix of developed and undeveloped land and includes the industrial and commercial centre of Dandenong; and
- southern part in which Frankston denotes the southern rim of the Melbourne metropolitan area and is the gateway to the Mornington Peninsula. Frankston is one of the largest retail areas outside the Melbourne CBD. The Mornington Peninsula is a 720 square kilometre boot-shaped promontory separating two contrasting bays: Port Phillip and Western Port. The Mornington Peninsula is surrounded by the sea on three sides, with coastal boundaries of over 190 kilometres.

The coverage of UE is shown in the figure below.

Figure 2: Distribution business boundaries - Victoria



In Victoria, each DNSP has responsibility for planning the augmentation of their distribution network and the associated transmission connection assets. In order to continue to provide efficient, secure and reliable supply to its customers, UE must plan augmentation of the network to match network capacity to customer demand. The need for augmentation is largely driven by customer maximum demand growth and geographic shifts of demand due to urban redevelopment.



3 Non-network alternatives

UE builds new electricity infrastructure to meet customers' increasing demand for electricity. This involves augmentation of the network with new transformers and new powerlines. Similarly UE replaces electricity infrastructure with new infrastructure when asset conditions deteriorate over time. These types of projects are generally referred to as 'network solutions'.

The nature of these network solutions are often capital intensive. At times more economical non-network options may exist which address the identified needs, but at a lower cost. Such non-network options may be temporary or permanent, but are generally designed to defer or replace a network solution.

Examples of non-network alternatives include aggregated demand management, distributed embedded generation and storage.

This chapter sets out when maximum demand generally occurs for UE, and how non-network options can assist in addressing the network limitations that the maximum demand causes at localised levels of the network.

3.1 MAXIMUM DEMAND OF THE DISTRIBUTION NETWORK

Electricity distribution networks are built to deliver electricity under all credible weather conditions, including on the extremely hot and very cold days of the year.

UE plans the network by forecasting its maximum demand, identifying the network limitations and quantifying the value of expected energy at risk of those limitations which take into account asset capabilities, failure rates and repair times.

UE's maximum demand forecasts are derived from a number of inputs including statistical temperature forecasts, new connections, changes in customer usage patterns, and economic indices.

Network limitations caused by maximum demand can be managed through either:

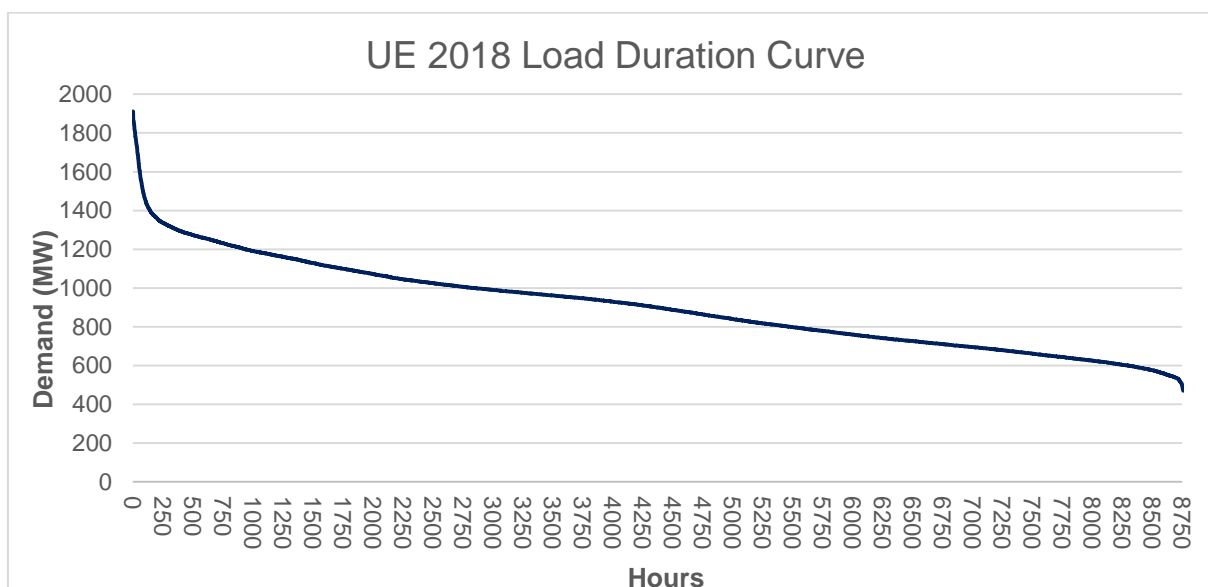
- increasing the network's capacity (augmentation);
- replacing assets to maintain the network's capacity (replacement);
- use of new technology options such as embedded generators or storage (e.g. battery storage); or
- reducing the electricity demand on the network (non-network options).

3.1.1 FREQUENCY OF MAXIMUM DEMAND

High electricity demand on UE's network typically occurs on the hottest days of the year when the temperature exceeds 35 degrees Celsius, for around five hours on each of those days. This corresponds to around 0.5% of hours in a year. Therefore, in an area of the network that has network limitations, a non-network option which reduces demand for only these hours may offer a preferable alternative to constructing new network assets.

The graph below shows the peak load duration curve for UE in 2018. This shows the relationship between the demand and the duration it exceeds a certain level on the UE network. The demand represents the coincident maximum demand of all customers across the UE network.

Figure 3: UE 2018 load duration curve



Non-network options can contribute to lowering the peak of the overall network by addressing maximum demand at a localised level.

3.1.2 SUMMER AND WINTER MAXIMUM DEMAND

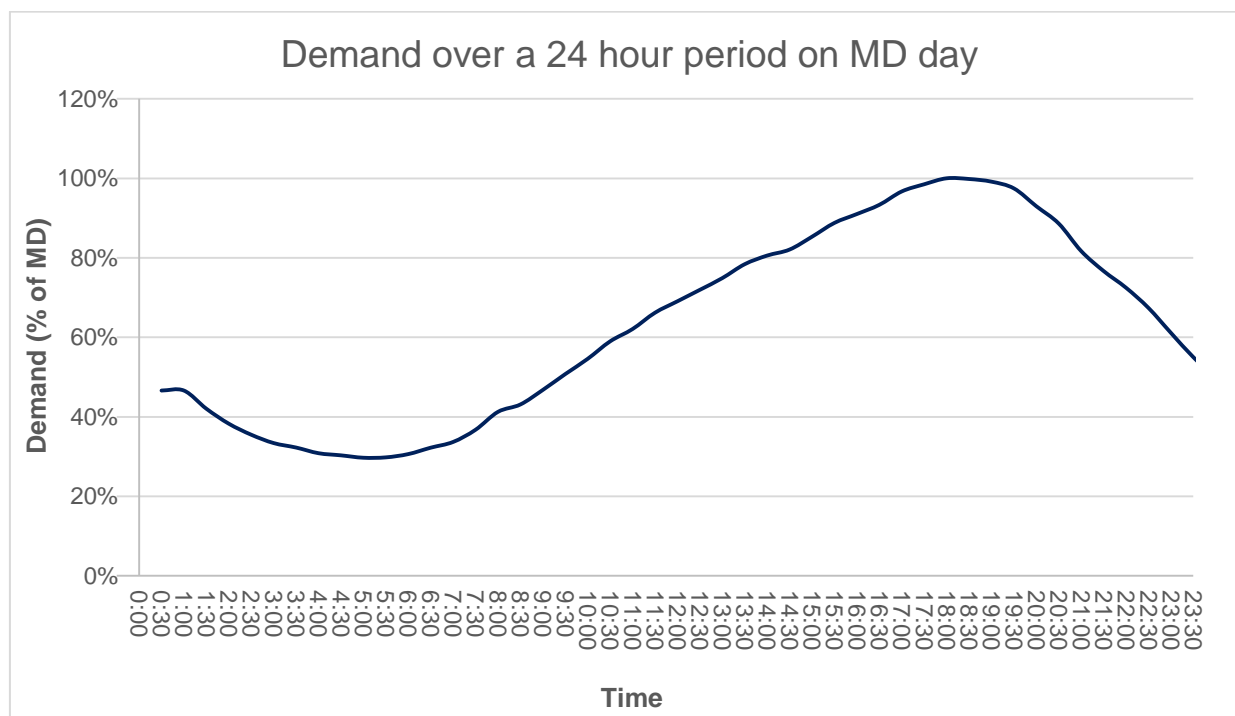
Summer peaking demand normally occurs on the hottest working weekdays between mid-November and mid-March. Locally it can occur from as early as 2pm for commercial areas to as late as 9pm where demand from residential customers is influential. Residential areas can even peak on weekends. From a total UE network perspective, the summer peak usually occurs around 5pm local time.

Winter peaking occurs on the coldest working weekdays in winter and can occur from as early as 5pm to as late as 10pm, however winter peaks are generally lower than summer peaks. From a total UE network perspective, the winter peak usually occurs around 6pm local time.

All parts of UE's network are currently summer peaking, meaning that the maximum demand occurs during the summer period.

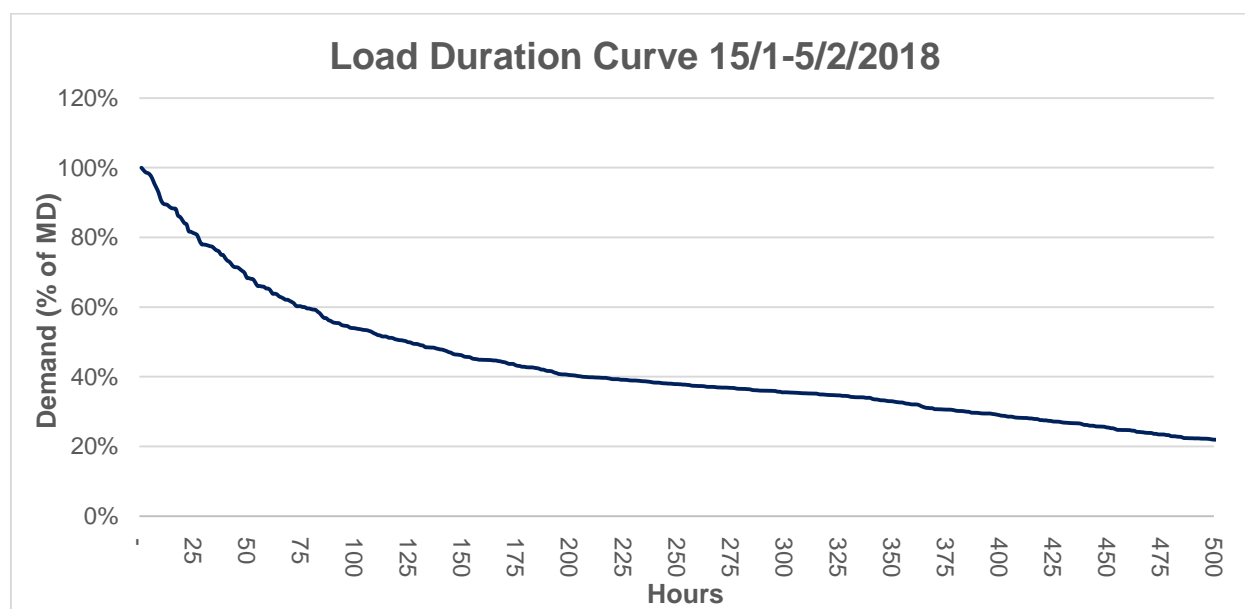
The figure below shows the daily electrical demand on a peak day for a typical summer peaking electricity substation, as typified by the Doncaster Zone Substation on 19 January 2018.

Figure 4: Maximum demand day at Doncaster Zone Substation



Maximum demand may occur for only a short duration in a given year. For example, in the area served by Doncaster Zone Substation during the hottest three weeks of summer 2018, the top 10 per cent of the demand only occurred for 10 hours. This is highlighted below.

Figure 5: Load duration curve Doncaster Zone Substation for the hottest three weeks



The effective and prudent use of non-network options can address localised network limitations associated with maximum demand, and thus may defer network augmentation or replacement.



3.2 USE OF NON-NETWORK PROVIDERS

Non-network solutions are an important component for the effective management of network limitations on the network and can involve either the reduction of customer electricity demand at peak times (demand management) or the direct supply of electricity at the distribution level (distributed embedded generation or storage).

Effective and prudent use of non-network solutions can reduce the need for network augmentation and associated maintenance costs if it is identified as the least lifecycle cost solution.

There are a range of non-network solutions that can be used by electricity networks including:

- aggregated direct load control or behavioural demand management:
 - a. shifting appliance or equipment use from peak periods to non-peak periods (e.g. controlled load (off-peak) water heating);
 - b. operating appliances at lower power demand for short periods (e.g. air conditioner duty cycling or thermostat set point change);
 - c. voluntary load curtailment by customers switching off appliances, such as in response to a request to reduce electricity usage.
- distributed embedded generation:
 - a. operation of embedded generators using conventional and renewable fuel sources synchronised to the grid.
 - b. use of stand-by generators to enable a customer to disconnect from the grid temporarily.
- energy efficiency and fuel switching:
 - a. converting the appliance energy source from electricity to an alternative (e.g. switching from electric to gas heating);
 - b. use of energy efficiency programs;
 - c. power factor correction of customer equipment to reduce the reactive power demand.
- storage:
 - a. storage devices such as batteries that can store energy in times of reduced demand and export energy at times of maximum demand;
 - b. storage coupled with renewable generation such as solar PV.

When a network limitation is identified, a review of options that includes both reducing demand and increasing capacity is initiated. The goal is to find the most efficient and prudent solution. Chapter 5 discusses UE's process for finding this solution.



3.3 DEMAND SIDE ENGAGEMENT REGISTER

UE maintains a register of parties wishing to be advised of publications, forums and consultations relating to the planning of UE's electricity distribution network. This is known as the Demand Side Engagement Register.

Notification to parties on the Demand Side Engagement Register will include information about upcoming public forums, the publication of any non-network consultation paper (RIT-D or otherwise), the publication of the Distribution Annual Planning Report (DAPR), and any other relevant publications relating to network planning.

UE will use the Demand Side Engagement Register not only to consult with interested parties, but also to gauge interest in joint planning activities relating to the development of non-network options.

To register your interest on UE's Demand Side Engagement Register, please lodge your details through the following link:

<https://www.unitedenergy.com.au/contact-us/demand-side-engagement-registration/>

4 Regulatory obligation

In January 2013, the Australian Energy Market Commission (**AEMC**) established a consistent national framework for distribution network planning and expansion. The national framework is applicable to UE's planning activities. This national framework requires UE to undertake annual planning, annual planning reporting, demand side engagement, and apply the RIT-D process in accordance with clause 5.13, 5.14, 5.15 and 5.17 of the NER.

The NER stipulates the following requirements on the development of the DSED:

- The DSED must include the information specified in schedule 5.9;¹
- The first DSED must be published no later than 31 August 2013;²
- The DSED must be reviewed and published at least once every three years.³

This version represents the third revision of the UE DSED.

5 Non-network management process

5.1 OVERVIEW OF NON-NETWORK MANAGEMENT PROCESS

This section of the DSED provides an overview of the process undertaken by UE to engage with potential non-network service providers with a view to facilitating the development of non-network options to address a current or emerging UE distribution network limitations.

This section also describes the criteria used to evaluate potential non-network options and the process undertaken by UE to further develop and implement the preferred non-network option(s).

¹ NER: clause 5.13.1(h)

² NER: clause 5.13.1(g)

³ NER: clause 5.13.1(i)



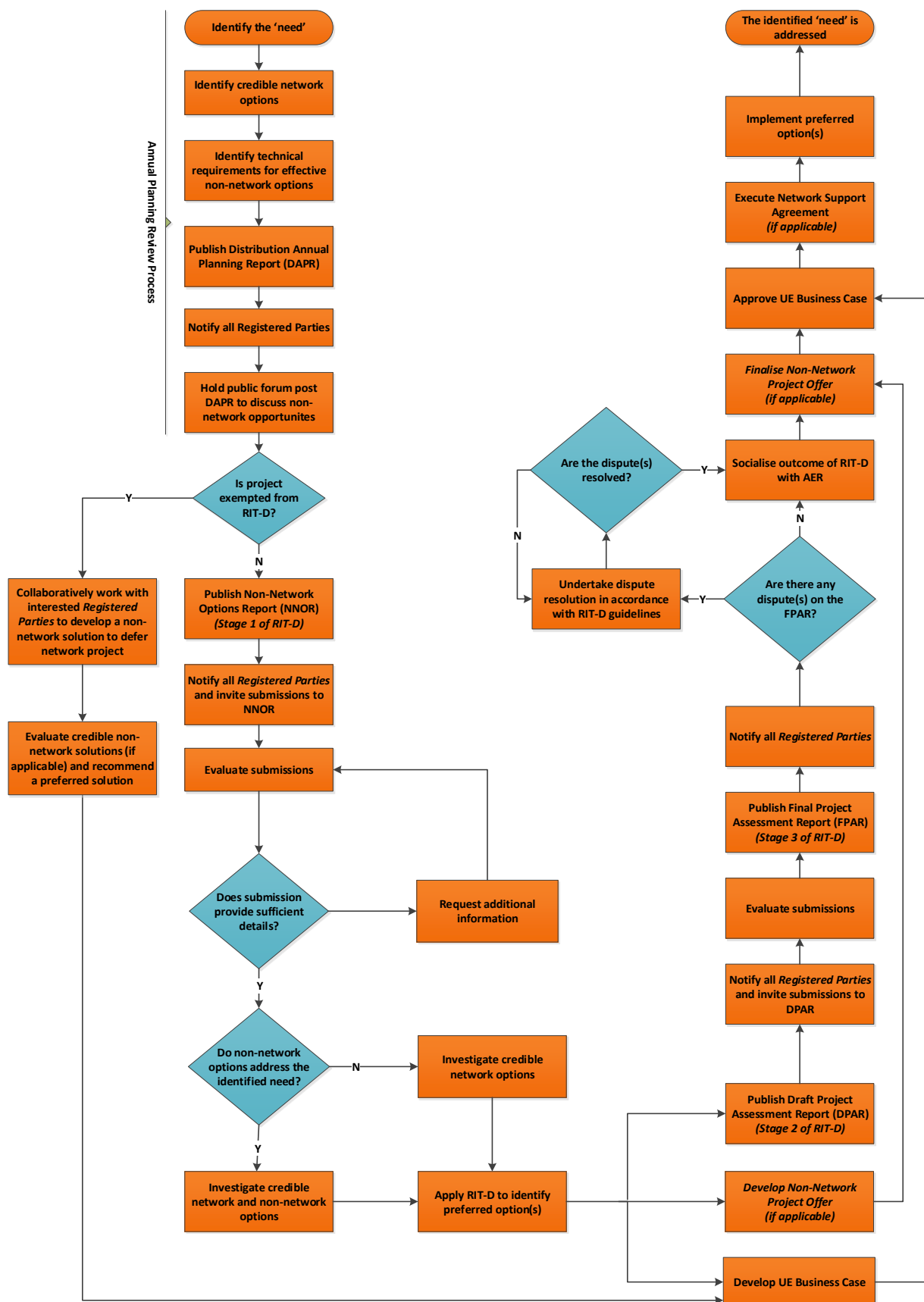
It should be noted that this process applies to both augmentation and replacement as the RIT-D has now been extended to also apply to replacement projects.

UE's non-network management process involves six primary steps:

1. Identifying opportunities for non-network options.
2. Public engagement.
3. Investigating and assisting development of non-network options.
4. Evaluating credible non-network solutions (if applicable).
5. Approving the preferred non-network solution (if applicable).
6. Implementing the preferred non-network solution (if applicable).

Figure 6 shows an overview of UE's non-network management process.

Figure 6 – An overview of UE's non-network management process





5.1.1 IDENTIFYING OPPORTUNITIES FOR NON-NETWORK OPTIONS

UE identifies potential non-network options for addressing network limitations by undertaking an annual planning review. UE's annual planning review:

- Identifies current and emerging network limitations;
- Determines the extent to which maximum demand or asset condition is driving the timing of investment; and
- Identifies the technical characteristics of non-network support required to address the limitation.

The current and emerging network limitations are characterised by location, load at risk (MVA), expected energy at risk (MWh per annum), duration (hours at risk) and the anticipated year that a solution is likely to be required.

Technical requirements for effective non-network options are similarly characterised by the

- location(s) where non-network solutions would be optimised;
- size which relates to the energy at risk and the growth in demand; and
- frequency and duration that the non-network service would need to be dispatched to alleviate the network limitation.

This information is published in December each year in UE's DAPR.⁴ UE also publishes project specific requests for non-network proposals via its Demand Side Engagement Register.

5.1.2 PUBLIC ENGAGEMENT

UE engages and consults with interested parties in the following ways:

- UE maintains its Demand Side Engagement Register for parties who wish to be regularly informed of UE's planning activities and consultations. UE also registers parties from CitiPower and Powercor's Demand Side Engagement Register where there is potential for a party to provide non-network services across multiple distribution service areas. As at 30 September 2018, UE had 99 registered organisations including 122 individuals on its Demand Side Engagement Register.
- UE notifies all parties on its Demand Side Engagement Register by email of non-network opportunities identified in its published DAPR. UE publishes the DAPR on its web site in December each year detailing areas where non-network opportunities exist. The DAPR seeks to engage the wider community in UE's network development planning, and encourages proposals for alternative non-network solutions.
- UE holds a public forum following the publication of each DAPR to discuss identified non-network opportunities in further detail. This public forum is held annually in early February at UE's office in Mount Waverley with teleconference facilities. All registered parties from UE's Demand Side Engagement Register are invited to attend.

⁴ UE Distribution Annual Planning Report (DAPR). Available at: <https://www.unitedenergy.com.au/industry/mdocuments-library/>

- UE proactively advises generator connection applicants to read the UE DAPR and register on the UE Demand Side Engagement Register at the connection enquiry stage to identify potential non-network opportunities to address an identified network limitation.
- UE facilitates the development non-network initiatives to address identified UE network limitations by establishing Memorandum of Understandings (MoUs) with registered interested parties. The MoUs seek to provide a joint planning framework to share data and explore non-network solutions to support shared strategic objectives for more efficient energy delivery. UE has 9 MoUs in place as of the time of publishing this DSED.
- UE will undertake public consultation during the RIT-D process (where required).

UE is required to undertake a RIT-D for network augmentation investments where the highest value credible option exceeds \$6 million⁵ unless exempted under NER clause 5.17.3.⁶ The purpose of the RIT-D is to identify and evaluate various distribution network investment credible options and recommend the most preferred option (be it network, non-network or a combination) that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

The RIT-D public consultation process involves three stages:

- Publishing a Non-Network Options Report (NNOR).
- Publishing a Draft Project Assessment Report (DPAR).
- Publishing a Final Project Assessment Report (FPAR).

All reports will be published on the UE website and parties on UE's Demand Side Engagement Register will be notified by email.

Registered and interested parties must make written submissions on the RIT-D reports within a minimum of:

- Three months from the publication date of the NNOR.
- Six weeks from the publication date of the DPAR.
- 30 days from the publication date of the FPAR.⁷

UE will clearly stipulate the closing date for submissions in the respective RIT-D reports.

The NNOR sets out the technical characteristics that a non-network option would need to deliver in order to address the identified network limitation. The public consultation period following the publication of the NNOR will be used to:

- Invite submissions from registered and interested parties.
- Engage with non-network service providers to further develop options (where applicable).

⁵ The threshold value is reviewed by the AER every 3 years. This value was determined in the November 2018 review.

⁶ The purpose, principle and procedures of the RIT-D are set out in NER clause 5.17. The threshold value is varied from time to time by the AER.

⁷ Registered Parties may dispute the findings in the FPAR. The disputing party must give notice to the AER and UE.

- Further populate UE's Demand Side Engagement Register with details of any parties that make a submission to UE.
- UE intends to share planning information and investigate potential non-network options to further develop credible solutions prior to undertaking a RIT-D assessment. UE recognises early engagement with non-network service providers is critical for successful development and efficient implementation of non-network solutions. UE is committed to actively engage with non-network service providers through joint planning initiatives.
- UE also consults with registered parties seeking to develop non-network solutions for network augmentation investments which are below the RIT-D threshold. In 2015-16, UE successfully deferred two distribution feeder augmentation projects (which were less than the RIT-D threshold of \$5m) by implementing a non-network solution on each of the two distribution feeders. In 2019 UE consulted with registered parties seeking non-network solutions to address distribution substation and low voltage circuit limitations.
- UE will seek opportunities to work with interested parties on initiatives which align with the objectives of the Demand Management Innovation Allowance (**DMIA**) funding for joint planning activities requiring specific studies, investigations or trials that may lead to the establishment of a non-network solution within the UE service area, in preparation for a future RIT-D identified in UE's DAPR.

5.1.3 INVESTIGATING NON-NETWORK OPTIONS

The purpose of the investigation process is to determine whether there are economically viable non-network options that could defer network investments, and to identify the size, performance characteristics, timing and costs of these options.

Submissions provided in response to the public consultation will be reviewed by UE and additional information may be requested for further clarification. UE will identify a range of credible non-network options by assessing a range of factors, including:

- Whether the technical requirements identified in the NNOR, or the request for proposal document (for RIT-D exempt projects), are satisfied including:
 - Capacity offered.
 - Availability and reliability of the service proposed.⁸
 - Frequency and duration for dispatching the service.
- Whether the proposed options would adversely impact the distribution network.⁹

⁸ The proposed option must be reliable and responsive to manage identified limitations. In the event that the network support service stipulated in the NSA is not provided, the non-network service provider may be subject to financial penalties. Under the Service Target Performance Incentive Scheme (STPIS), UE is penalised when service performance is worse than performance targets. Any penalties incurred by UE under the STPIS scheme due to unavailability of the non-network support may be passed onto the non-network service provider.

⁹ A significant consumption of existing capacity headroom in fault level or quality of supply, triggered by the connection of a non-network solution, could bring forward the timing of network investment. Any marginal costs associated with early investment compared with planned would be borne by the non-network service provider.



- The total cost (capital and operating costs over the lifecycle) including any associated costs to augment the distribution network, triggered by the connection or operation of the non-network option. Fixed and variable costs should be clearly identified.
- The timing for delivery (including timeline to plan and implement).
- Any risks in delivery.
- The number of years the non-network option is planning to defer the preferred network option.¹⁰
- Compliance with relevant rules and connection standards.¹¹
- The non-network service provider's capability and experience.
- The non-network service provider's commitment to enter into a Network Support Agreement (NSA)¹² with UE (based on agreed terms and conditions). UE's standard NSA is available for non-network service providers upon request. (Refer to Section 9 for further detail).
- Letters of support from partner organisations.
- Other additional information needed to assist UE in investigating and evaluating the credible non-network options.

The next stage of the investigation process is to identify the preferred option (be it network, non-network or a combination of both). The preferred option maximises the net present value of market benefits which is identified via cost-benefit assessment of all credible options as defined in clause 5.17 of the NER.

UE believes that the classes of market benefits that are most likely to change as a result of removing network limitations by implementing non-network options are:

- Changes in voluntary load shedding.
- Changes in involuntary load shedding.
- Changes in network losses.
- Differences in the timing of network investment expenditure.
- Changes in costs for parties¹³ other than the proponent.

These impacts will be calculated according to the AER's published RIT-D application guidelines¹⁴.

¹⁰ Minimum of one year (full) deferral of the preferred network augmentation would be required.

¹¹ If generation operating in parallel with UE's distribution network is proposed as a non-network option, the generator must meet all relevant NER and UE requirements related to grid connection. The generator must submit a separate Application to Connect to UE, demonstrating its ability to meet UE's Embedded Generation Network Access Standards.

¹² If generation operating in parallel with UE's distribution network is proposed as a non-network option, the generator must enter into a generator connection agreement with UE prior to entering into a NSA.

¹³ This would be consistent with the definition captured by RIT-D.

¹⁴ Regulatory investment test for distribution Application Guidelines: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018>

5.1.4 DEVELOPING THE PREFERRED NON-NETWORK SOLUTION

UE plans to facilitate the development of non-network solutions through consultation and through contractual arrangements with the non-network proponent of the preferred option.

- Developing RIT-D consultation papers

UE aims to release the outcomes of the non-network options investigation in a RIT-D stage 2 consultation report (DPAR) at least four months from publishing the NNOR. In the event no non-network options are found to be feasible, then this will be clearly stated in the DPAR. The DPAR will:

- Describe the network limitation that UE is seeking to address – the ‘need’
- Summarise submissions received on the NNOR
- Provide commentary on UE’s response to submissions
- Describe the credible options (network, non-network or a combination) that UE has assessed which may address the identified network limitation
- Quantify costs (with a breakdown of operating and capital expenditure)
- Describe the method adopted in assessing market benefits
- Provide results of the Net Present Value (NPV) assessment for each credible option
- Identify the preferred option(s).

UE aims to publish the DPAR as soon as practically possible, after the end of the consultation period on the DPAR.

The FPAR will:

- Update the information provided in the DPAR
- Summarise submissions received on the DPAR
- Provide commentary on UE’s response to submissions
- State the preferred option with reasoning.

The proponent with the non-network option that satisfies the RIT-D would be eligible to receive a Non-Network Project Offer from UE.

- Developing Non-Network Project Offers

In the event that a non-network option is selected as the preferred option, the project will be developed into a Non-Network Project Offer which consists of (but not limited to):

- A UE standard Network Support Agreement (NSA)
- Defining the scope of the non-network solution, including:



- Quantifying the non-network service to be provided
 - Timing
 - Payment schedule
 - Penalty schedule (if applicable).
- Undertaking contract negotiations to confirm terms and conditions of the NSA.
- Developing UE business case

UE's project development process which culminates in the approval of a business case will be undertaken in parallel with the consultation process.

5.1.5 APPROVING THE PREFERRED NON-NETWORK SOLUTION

Following the publication of the FPAR, or assessment process for specific RIT-D exempt projects, UE will:

- Socialise the outcome of the RIT-D to the AER.
- Seek internal approval of the preferred option through a business case.
- Finalise contract negotiations with the proponent of the preferred non-network option via an NSA.

All of the above are required to be concluded to achieve approval of the non-network solution.

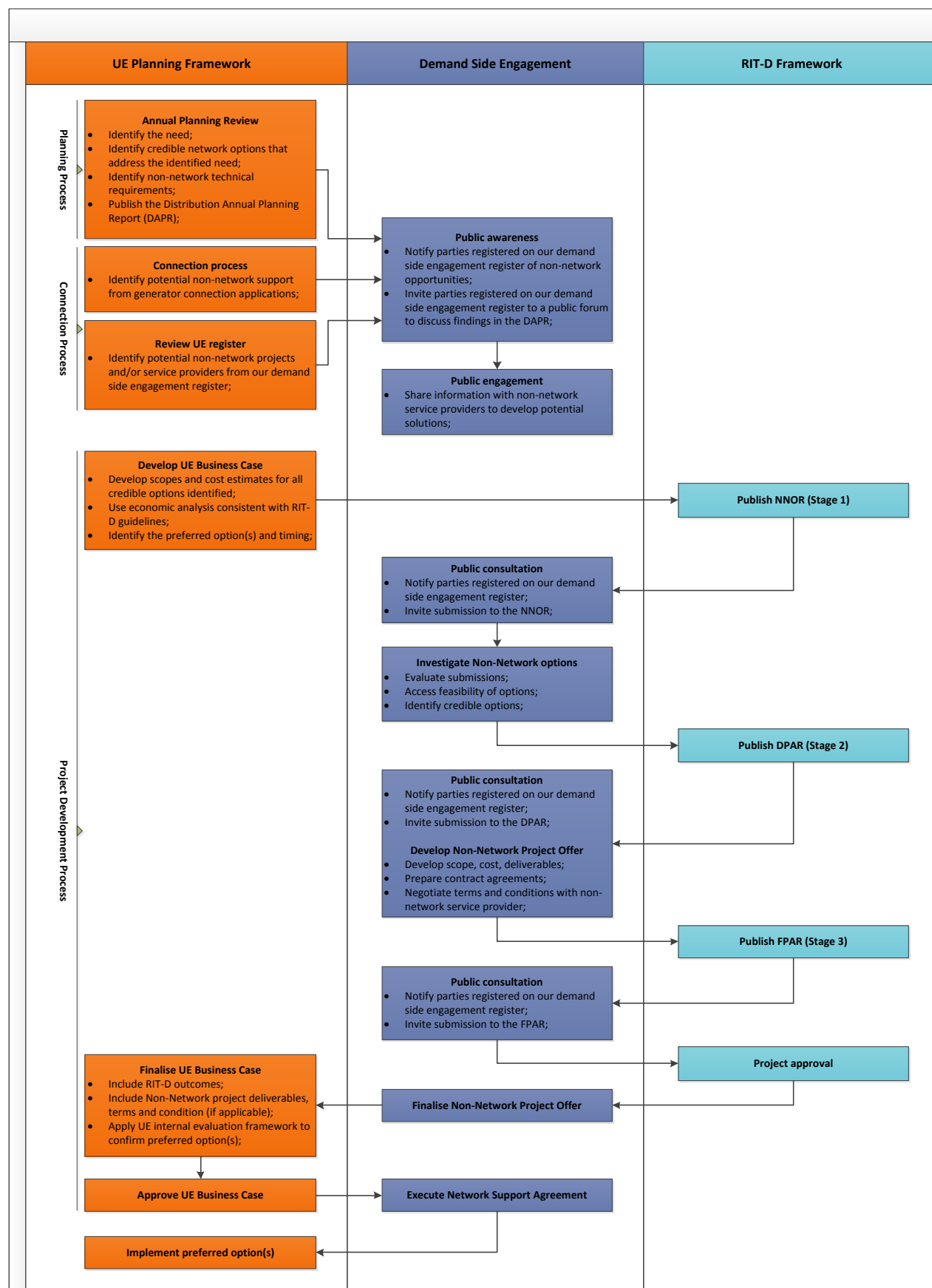
5.1.6 IMPLEMENTING THE PREFERRED NON-NETWORK SOLUTION

For access to payments, the non-network solution can proceed once the UE business case is approved and the NSA is executed. Integration of the non-network project into the UE network will follow the approach outlined in the Non-Network Project Offer.

5.2 ALIGNMENT WITH UE'S PLANNING FRAMEWORK

This section demonstrates the alignment of the DSED and RIT-D with UE's planning and project development process.

Figure 7 – Alignment of the DSED with UE’s planning framework





5.2.1 UE PLANNING PROCESS

This DSED is aligned with UE's planning process. Further information on UE's planning process and method can be found in UE's network planning reports available (under the Regulatory reports section) at:

<https://www.unitedenergy.com.au/industry/mdocuments-library/>

5.2.2 UE PROJECT DEVELOPMENT PROCESS

UE's project development process which culminates in the approval of a business case will be undertaken in parallel with the RIT-D process. The timeline for the RIT-D requirements will take into consideration the timing of project key milestones. It is planned the business case approval will occur after the conclusion of the RIT-D once the RIT-D is satisfied and the preferred option (be it network or non-network) has been identified.

UE proposes that the project development process will occur in parallel with the RIT-D as follows:

- UE's project development process commences with the annual Asset Management Planning activity. Network projects are identified through the Asset Management Planning activity, using maximum demand forecasts and asset condition information, to identify emerging network supply limitations. A number of network project options are assessed and the most likely network option to alleviate the network limitation is budgeted in the Asset Management Plan at the likely time it would be needed, taking into account project lead times. The DAPR is a public version of this planning activity.
- Detailed project scopes are developed for each option and these are priced either internally or with the assistance of UE's service providers. UE's service providers and panel contract members will be invited to submit a bid for the network augmentation tender during first stage of the RIT-D process, so they can directly compete with the non-network service providers. The winning tender price would be used in both the RIT-D evaluation process and the UE business case development.
- A draft business case is developed using an economic analysis relatively consistent with to identify the preferred network option, and its timing. Once the business case economics and optimum timing is confirmed, the RIT-D process or consultation process for specific RIT-D exempt projects is initiated.
- If the RIT-D or consultation process confirms the network option, UE will proceed with its internal approval process to approve the business case for the preferred network option and commence the network augmentation project. If the RIT-D or consultation process identifies a non-network solution, UE will proceed with its internal approval process to approve the business case for the preferred non-network option. Contract negotiations will then commence with the non-network proponent.

5.2.3 UE GENERATOR CONNECTION PROCESSES AND STANDARDS

UE undertakes the connection process for embedded generator connections in accordance with Chapter 5 and Chapter 5A of the NER.



Chapter 5

- Applicable for all embedded generation with capacity above 5MW
- These generators must be registered (as per NER definition) or apply for an exemption with AEMO.
- This process is generally for larger embedded generation connections at distribution and or transmission high voltage level such as wind farms or peaking synchronous generators.

Chapter 5A

- Applicable for majority of below 5MW capacity embedded generation
- These are non-registered generators (as per NER definition)
- This process is generally for smaller embedded generation connections at distribution high and or low voltage such as solar or small scale co/tri-generation systems.

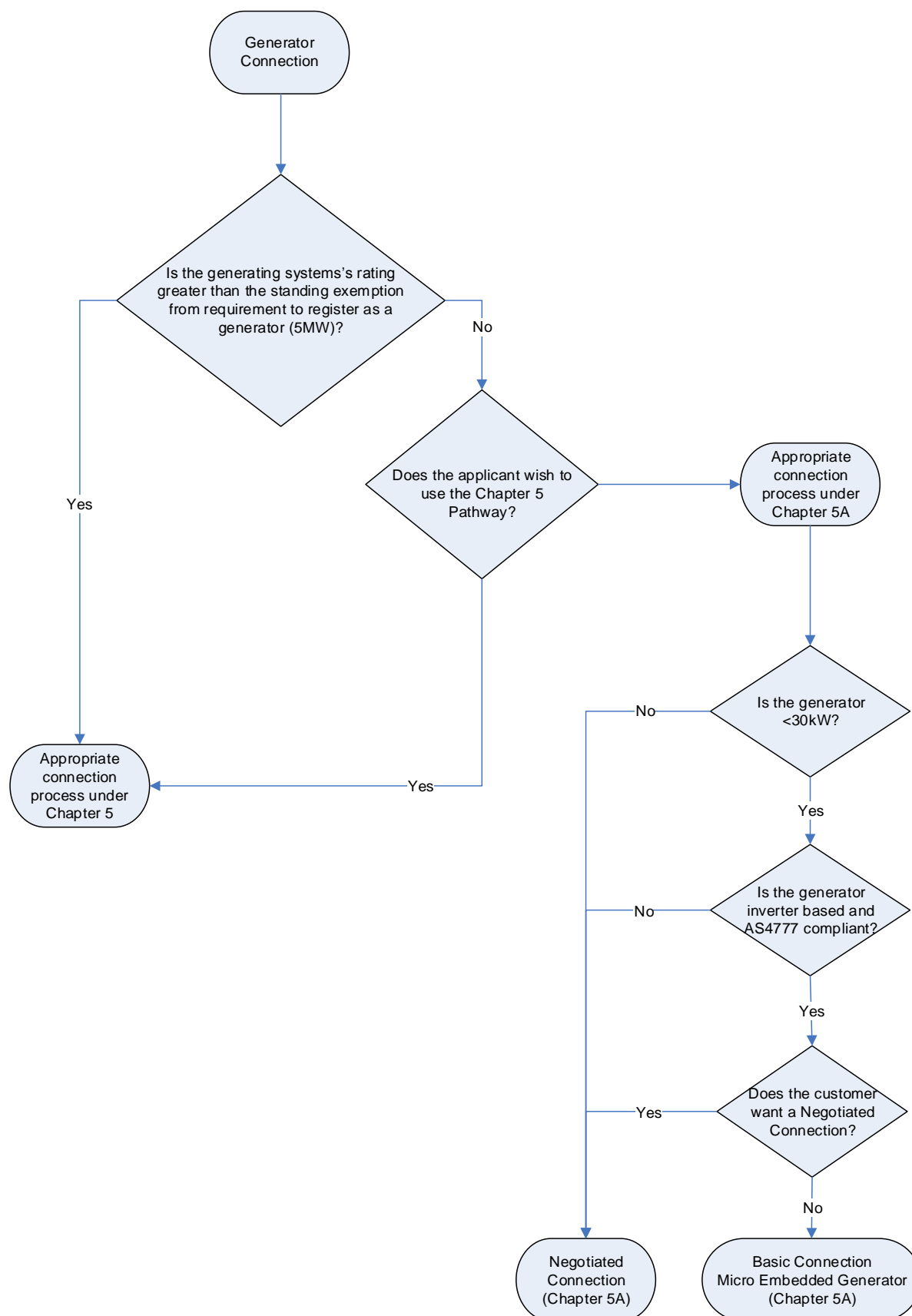
A connection applicant with a generator connection below 5MW may choose to use the Chapter 5 connection process. This must be requested in writing to UE.

The merits of each connection process is briefly outlined below:

Chapter 5	Chapter 5A
More defined and detailed	More flexible
Generally longer	Generally shorter

Please see Figure 8 for the generator connection framework.

Figure 8 – Generation Connection Framework





UE's process and access standards for connection of embedded generation to the distribution network are detailed in UE's Embedded Generation Network Access Standards (Document No. UE ST 2008)¹⁵. This document is publically available on the UE website and advised by UE to all connection applicants at the time of a generation connection enquiry.

This connection process can occur at any time and may run concurrently with the RIT-D process.

The following sections outline the different connection processes available to a connection applicant.

5.2.3.1 BASIC CONNECTION

The Basic Embedded Generation Connection process has been designed to accommodate the majority of embedded generation applications received by UE. This is a streamlined connection process designed for most residential and small scale commercial solar and battery applications. Any connection applications which do not meet the criteria listed in Figure 8 are required to use the Negotiated Process.

For more information regarding this process and the model standing offer (contract), please refer to the Connections page on the UE website.

5.2.3.2 NEGOTIATED CONNECTION

Negotiated connections are available under both the Chapter 5 and 5A framework.

The main stages of the Negotiated Connection process are:

- Preliminary Enquiry
- Detailed Enquiry (only for Chapter 5)
- Application to Connect
- Connection Offer
- Sanction to Connect.

Please see Figure 9 and Figure 10 for the Chapter 5A and 5 connection processes respectively.

5.2.3.3 NEGOTIATED GENERATOR CONNECTION ASSESSMENT CONSIDERATIONS

The following high level factors are taken into considerations by UE during the Connection Enquiry and Application to Connect process;

- Network Safety, Security and Stability;
- Network infrastructure availability, capability and capacity to facilitate the proposal;
- Infrastructure and commercial demarcation and crossover, especially when multiple jurisdictions are involved;
- Where applicable, compliance and alignment with the RIT-D requirements.

¹⁵ <https://www.unitedenergy.com.au/wp-content/uploads/2015/09/UE-ST-2008-Embedded-Generation-Network-Access-Standard-V1.3.pdf>

- Consideration for non-network support opportunities (especially in areas of network limitations identified under the DAPR).
- Depending on proposal, suitable communications infrastructure to facilitate technical as well as NEM market control requirement (protection and or generator scheduling operation);
- Embedded generation network impact (and nearby customers);
- Network and Proposal Interconnection Protection;
- Network Infrastructure Thermal Capacity;
- Network Voltage Control;
- Generator Fault Level Contribution;
- Power Factor of Generator Operation;
- Power Quality of Supply Generated;
- Generator Operations (Modus Operandi: Renewables, base, peaking etc...);
- Network augmentation (i.e. infrastructure upgrade) likely to be required to facilitate the proposal and commercial model such as contestability, construction, ownership, the classification of services provided and associated costs;
- Other jurisdiction approvals (lease, easements, council planning etc.);
- Network scope of work delivery timeframe;
- Legal, commercial and financial due diligence of the entity entering into the agreement;
- All other suitable considerations unique to the proposal.

5.2.3.4 CHARGES ASSOCIATED WITH NEGOTIATED GENERATOR CONNECTION AND AGREEMENT

Chapter 5 and 5A of the NER governs the processes associated with the generator connection charges. As each negotiated generator connection exhibits uniqueness, the associated generator connection services and charges are formulated specific to the proposal. This has many dependent factors including but not limited to: network capability and capacity, generator capacity, connection voltage, modus operandi, augmentation requirements and connection complexity of the proposal.

To formalise the connection, the connection applicant would be financially responsible for:

- the full cost of the generator connection assets and services; and
- any cost of removing the distribution network limitations that are specific to the connection of the generator.

The connection applicant is also financially responsible for settlement of the charges specific to the connection process to cover the expenses reasonably incurred by UE. These include but are not limited to:

Preliminary/Detailed Enquiry

- Application Processing Fee



Application to Connect – Connection Charges

These typically constitute:

- Field and or Network Augmentation Works. If significant this may be subject to a separate commercial contract (per application)
- Expenditure recuperation for applications which expanded beyond the original scope
- Legal and commercial negotiation charges
- Commissioning works such as inspections and or validation
- Connection Sanction review

For further information of all service charges, fees and rates, please consult the UE Connection Charging Policy and Chapter 5 and 5A Information Packs on the UE website.

Additionally the UE website publically makes available and maintains the template application forms and the generator agreements (model standing offer) associated with both negotiated Chapter 5 and Chapter 5A frameworks. These template forms, technical standard, website information, guidelines and agreements constitute the information pack to be utilised as the initial engagement point for all negotiated generator connections.

Figure 9 - Chapter 5A Connection Process

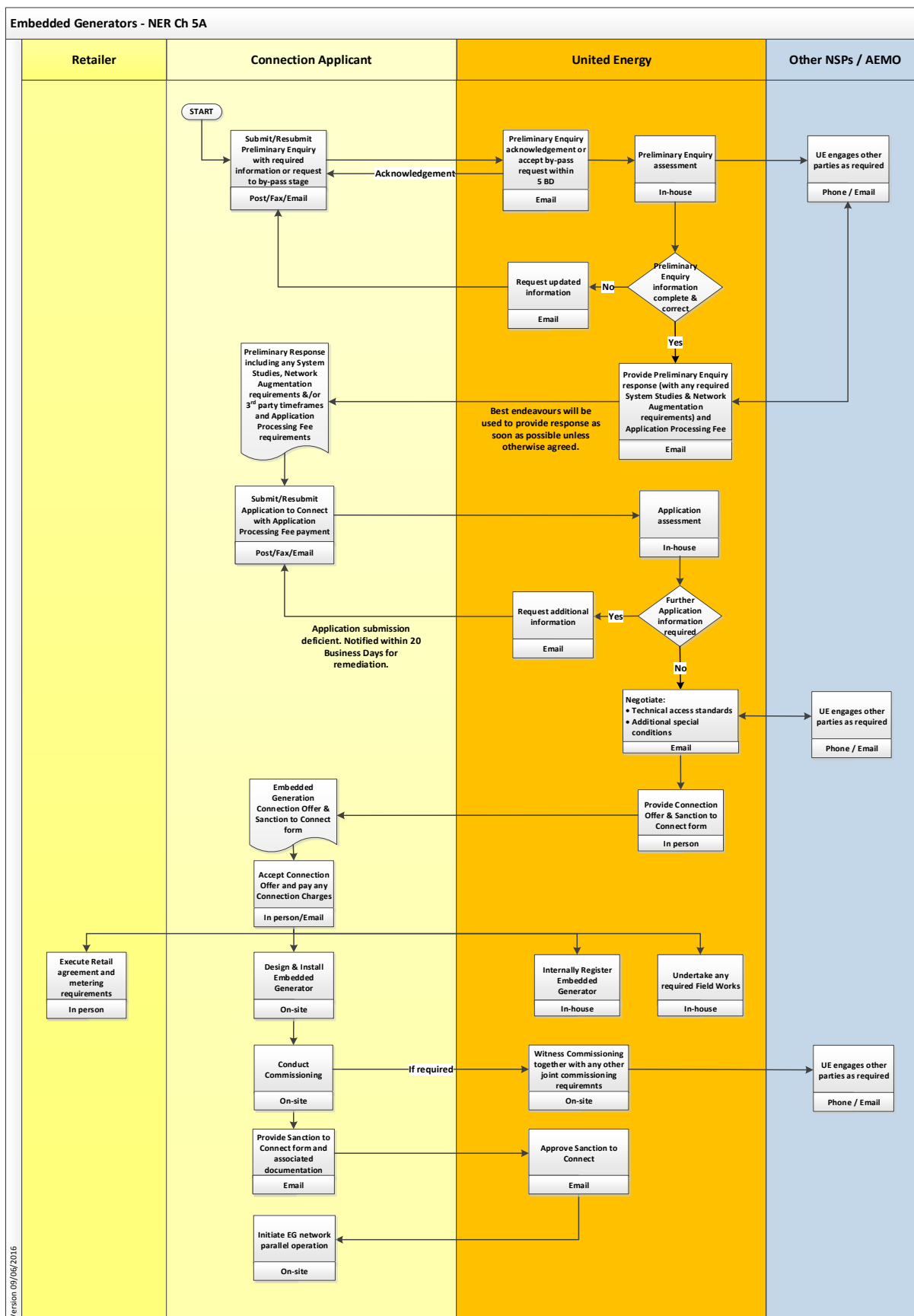
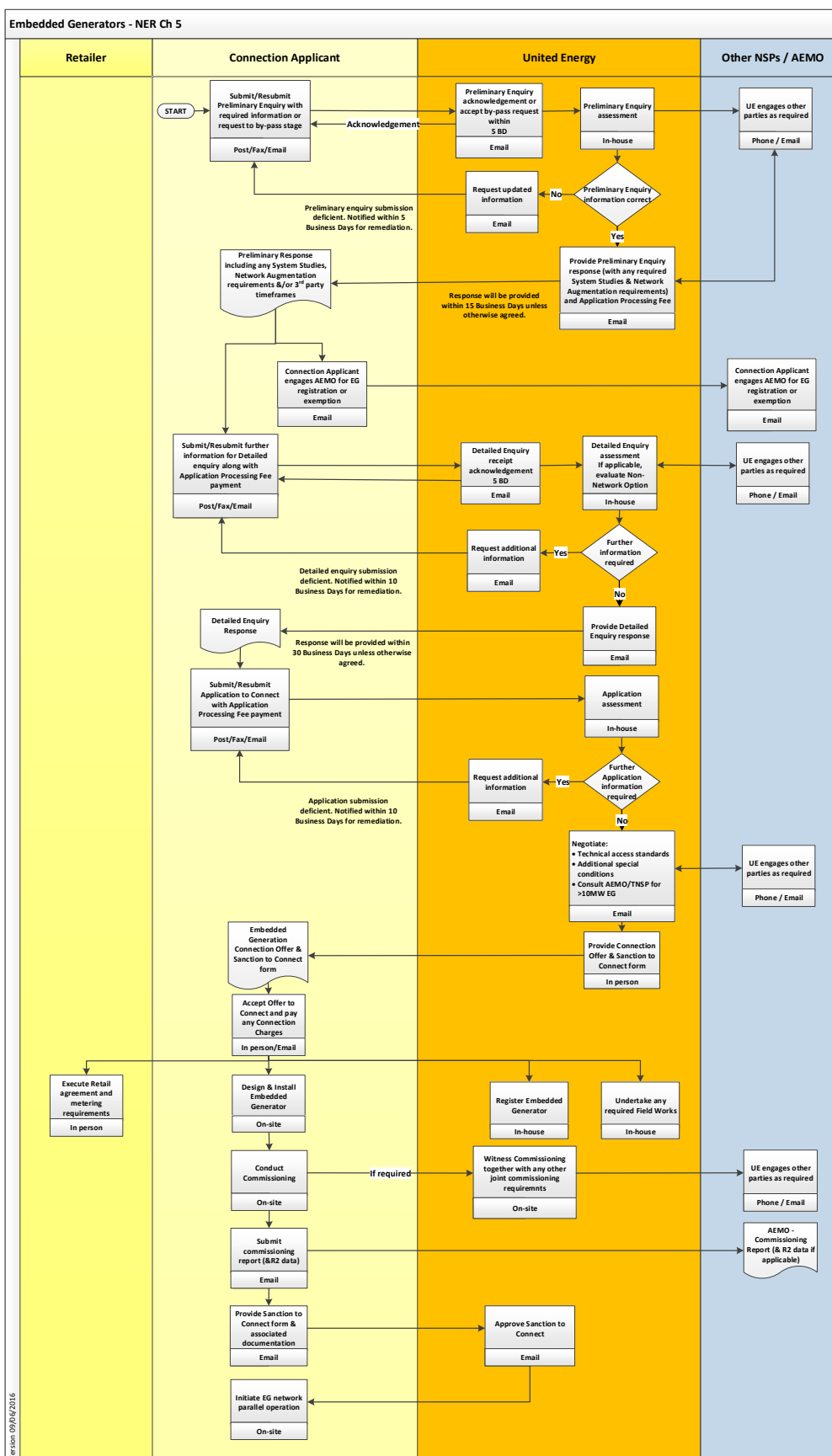




Figure 10 - Chapter 5 Connection Process





6 Request for non-network opportunities

6.1 DATA REQUIREMENTS FROM NON-NETWORK SERVICE PROVIDERS

Non-network service providers interested in providing submissions to alleviate network limitations outlined in the NNOR or a request for proposal should contact UE as soon as possible. A detailed proposal including the information listed below should be submitted by the requested date stipulated in the notification. Submissions of detailed information in a timely manner would ensure that sufficient time is available to assess all alternative options and conduct a cost-benefit assessment as required by the RIT-D guidelines. Details required include:

- Name, address and contact details of the person making the submission.
- Name, address and contact details of the person responsible for non-network support (if different to above).
- A detailed description of services to be provided including:
 - Size (MW/MVA)
 - Location(s)
 - Frequency and duration
 - Type of action or technology proposed
 - Proposed dispatching arrangement
 - Availability and reliability performance details
 - Period of notice required to enable the non-network support
 - Proposed contract period
 - Proposed staging (if applicable)
 - Proposed timing for delivery (including timeline to plan and implement).
- High-level electrical layout of the proposed site (if applicable).
- Evidence and track record proving capability and previous experience in implementing and completion of projects of the same type as the proposal.
- Preliminary assessment of the proposal's impact on the network.
- Breakdown of lifecycle cost to providing the service, including:
 - Capital costs (if applicable)
 - Annual operating (i.e. set up and dispatch fees) and maintenance costs
 - Other costs (e.g. Availability, Project Establishment costs etc. with fixed and variable costs clearly defined).



- Where appropriate, evidence of a planning application having been lodged.
- A method outlining measurement and quantification of the agreed service, including integration of the proposed solution with the UE network.
- A statement outlining that the non-network service provider is prepared to enter into an NSA with UE (subject to agreeing terms and conditions).
- Letters of support from partner organisations.
- Any special conditions to be included in an NSA with UE.

All proposals must satisfy the requirements of any applicable laws, rules and the requirements of any relevant regulatory authority. Any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent of the non-network options.

6.2 TECHNICAL REQUIREMENT FOR NON-NETWORK OPTIONS

UE will review submissions provided in response to the NNOR, and may seek additional information if required. A credible non-network option must satisfy the timing, operational and technical requirements stipulated in the NNOR, and provide at least one full year deferral of the proposed network investment. If the non-network option is a generator operating in parallel with UE's network, the generator must comply with the requirements set out in UE's Embedded Generation Network Access Standard (Document No. UE ST 2008)¹⁶.

A non-network service provider may aggregate generation and/or a portfolio of customers' demand to form a credible non-network option. A non-network service provider may also form a consortium of non-network service providers to aggregate capabilities to form a credible non-network option. In these cases, it is the responsibility of the lead non-network service provider to undertake contract negotiations with customers/other service providers and warrant that the aggregated service proposed meets the requirements stipulated in the NNOR.

7 Non-network incentive payments

7.1 APPLICABLE INCENTIVE SCHEMES

The following funding arrangements may be available for non-network solutions:

1. Avoided TUoS charges.
2. Deferred distribution augmentation annualised cost.
3. Demand Management Incentive Allowance (DMIA).

7.1.1 AVOIDED CUSTOMER TUOS CHARGES

The Transmission Use of System (**TUoS**) charges recover the cost for provision of shared transmission network services and transmission connection asset services in Victoria. AEMO

¹⁶ <https://www.unitedenergy.com.au/wp-content/uploads/2018/05/UE-ST-2008-Embedded-Generation-Network-Access-Standard-V1.3.pdf>



calculates TUoS charges in accordance with Chapter 6A of the NER. The TUoS charges are based on an average of the top ten summer maximum demands at each connection point.¹⁷

The avoided TUoS charges represent the difference in TUoS charges that would be payable by UE had the non-network proponent not connected to the network (for the locational TUoS component only). UE will calculate the avoided TUoS charges in accordance with clause 5.5 of the NER. The calculations and more details are shown in Appendix A.

7.1.2 DEFERRED NETWORK OPTION ANNUALISED COSTS

The deferral of a network option is calculated by comparing the net present value (NPV) of the base case (i.e. do nothing) with the non-network option in place, referenced to the investment year under both scenarios. Cash flows are expressed in real terms and the discount rates relate to the UE Weighted Average Cost of Capital (**WACC**).

The full financial incentives are equivalent to the avoided annualised cost of the deferred augmentation. Non-network service providers may be eligible for maximum annual network support payment of up to regulatory rate of return¹⁸ × total capital cost plus any additional operating costs of the network augmentation provided the non-network option meets the full service requirements and continues to defer the network option.

Part of the full financial incentives may be offered to non-network service providers based on negotiated reliability and performance levels if there are tangible, quantifiable differences between the service level provided by the non-network solution and the network solution.

7.1.3 DEMAND MANAGEMENT INNOVATION ALLOWANCE (DMIA)

The DMIA provides a limited regulatory allowance for UE over the regulatory period to fund projects that lead to the development of efficient non-network solutions to defer planned network augmentation. The AER has developed criteria and reporting requirements for using this funding¹⁹.

For the 2016-2020 regulatory control period, UE has been allocated \$400k per annum in the AER's regulatory reset determination (\$2M over five years) as an ex-ante allowance under the DMIA. UE is on track to use all its funding as it did in the previous regulatory period. Projects which UE have used funding over the current period are:

- UE Summer Saver Program (which has now transitioned to a business as usual demand management program),
- Virtual Power Plant (VPP) Residential Pilot Project,
- Grid Side Storage Trial,
- Deakin University Summer Saver Study,
- ClimateWorks Monash Demand Management Study,
- City Smart Summer Saver.

¹⁷ <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Fees-and-charges>

¹⁸ This is based on the regulatory WACC and asset life.

¹⁹ Demand Management Incentive Scheme. Available at: <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism>



We encourage non-network service providers approach UE (Refer to Section 9 for further detail) to enquire about opportunities to use DMIA for joint planning activities requiring specific studies, investigations or trials that may lead to the establishment of a non-network solution within the UE service area, in preparation for a future RIT-D identified in UE's DAPR.

The non-network proponent should provide UE an explanation of the non-network project for which DMIA funding is sought including:

- The nature and scope of the project.
- The aims and expectation of the project.
- Information on how the project will be implemented.
- Identification of benefits arising from the project, including any off-peak or maximum demand reductions.
- Information on the costs of the project, including business case for the project and consideration of any alternatives.

A description on how the proposal helps to meet the objectives of the DMIA.

8 Worked examples

UE has successfully completed three RIT-D consultation processes, which are:

1. Dromana Supply Area RIT-D
2. Lower Mornington Peninsula Supply Area RIT-D
3. Notting Hill Supply Area RIT-D

The lower Mornington Peninsula RIT-D assessment confirmed a 4-year demand management non-network solution as a preferred option to defer the network augmentation by two years. This section contains worked examples which demonstrate how UE assesses the potential non-network options. UE has also provided an example of where DMIA funding has been used to investigate a potential non network option in the Doncaster supply area (see example 4).

8.1 EXAMPLE 1 - DROMANA SUPPLY AREA RIT-D

Dromana (**DMA**) zone substation was commissioned in March 2006, as a single transformer zone substation, to provide load relief to neighbouring Mornington (**MTN**) and Rosebud (**RBD**) zone substations. From inception, DMA had showed a steady growth in weather-corrected maximum demand, with the actual summer maximum demand in 2011-12 exceeding the nameplate rating of the transformer. Based on the 2012 maximum demand forecast, the 10% PoE summer maximum demand at DMA was expected to exceed the station's 'N' cyclic rating in summer 2017-18.

8.1.1 NETWORK LIMITATION

Given DMA was a single transformer zone substation, customers' supply was normally restored via the distribution feeder network from neighbouring zone substations at MTN and RBD, following the loss of the zone substation transformer or other fault resulting in the total loss of supply to DMA. Due to on-going customer load growth, the spare capacity in the neighbouring network during high demand periods had diminished below the summer maximum demand at DMA. As a result, some customers

could have potentially been without electricity supply until the capacity in the neighbouring network became available. Based on the 2014 maximum demand forecast, some customers were expected to be without electricity supply from summer 2014-15, following the loss of the transformer during high demand.

The distribution network from DMA zone substation is characterised by relatively long distribution feeders. As a result, a number of distribution feeders within the DMA supply area have shown poor reliability performance compared to the overall UE network. More specifically, DMA 13 was the worst performing feeder on the UE network. Furthermore, DMA 14 and DMA 15 were also amongst the worst 50 rogue feeders.

A number of distribution feeders within the DMA and MTN supply areas were also forecast to exceed their thermal capability. More specifically, the 10% PoE summer maximum demand on DMA 12 was expected to exceed its thermal capability in summer 2014-15. Pre-summer load transfers to neighbouring feeders were no longer possible.

8.1.2 PROPOSED NETWORK OPTION

The following options were included as potential credible options in the RIT-D assessment.

Table 1 – Credible options considered in the RIT-D

RIT-D Option	Description
Option 1	<p>This option includes:</p> <ul style="list-style-type: none"> Installing a new 20/33 MVA 66/22 kV transformer at Dromana zone substation. Extending the 22 kV indoor busbar at Dromana zone substation. Upgrade of existing protection and control schemes. Developing two new 22 kV distribution feeders to supply the existing loads in and around Dromana area, including rearrangement works. <p>The estimated total cost, inclusive of operating costs, is estimated at \$8.4 million (in 2015-16 PV terms).</p>
Option 2	<p>This option includes:</p> <ul style="list-style-type: none"> Installing a new 20/33 MVA 66/22 kV transformer at Mornington zone substation. Developing three new 22 kV distribution feeders at Mornington zone substation to supply the existing loads in and around Dromana area. Developing one new 22 kV distribution feeder at Rosebud zone substation to supply the existing loads in and around Dromana area. <p>The estimated total cost, inclusive of operating costs, is estimated at \$17.3 million (in 2015-16 PV terms)</p>

8.1.3 PROPOSED NON-NETWORK OPTION

On 28 March 2014, UE published the NNOR providing details on the network limitations within the Dromana supply area. This report sought information from Registered Participants and Interested Parties regarding alternative potential credible options or variants to the potential credible options presented in that report.

In response to the report, UE received enquiries from several non-network service providers. UE took this opportunity to further populate its Demand Side Engagement Register and engaged in joint planning with those proponents to assess the viability of alternative credible options within the Dromana supply area. UE received two submissions by 20 June 2014, being the closing date for submissions to the NNOR. Both submissions indicated that there are no identified credible alternative options within the Dromana supply area.

On 13 August 2014, UE published the DPAR in accordance with clause 5.17.4(j) of the NER. The purpose of this report was to provide a basis for consultation on the proposed preferred option to address the network limitations within the Dromana supply area. This report stated that the recommended action would involve the installation of a new 20/33 MVA 66/22 kV transformer at Dromana zone substation together with two new distribution feeders by November 2016.

Once again registered participants and interested parties were invited to lodge submissions on the matters outlined in the DPAR by 26 September 2014.

Following a detailed economic assessment, in the absence of a non-network solution, recommended preferred solution involved Network Option 1 as outlined in Table 1.

No submissions were received.

8.1.4 PREFERRED OPTION

UE defined a number of reasonable scenarios to test the robustness of this RIT-D assessment: the 'base case' (or the most likely scenario), and several other scenarios which represented plausible combination of upper and lower bound assumptions on the key variables of demand growth, investment cost, value of customer reliability and discount rate. Following a detailed economic assessment and scenario testing, in the absence of any credible non-network solution, the recommended preferred solution involved Network Option 1 as outlined in Table 2.

Table 2 - Net market benefits of each credible option under base case scenario (PV, \$m)

Scenario	Do Nothing		Network Option 1		Network Option 2	
	Net Economic Benefit	Ranking	Net Economic Benefit	Ranking	Net Economic Benefit	Ranking
Base case	0	3	19.77	1	3.60	2

UE published the FPAR on 9th October 2014 to conclude the RIT-D process. No submissions were received.

8.2 EXAMPLE 2 - LOWER MORNINGTON PENINSULA SUPPLY AREA RIT-D

The lower Mornington Peninsula is supplied by a 66kV sub-transmission network supplying Dromana (**DMA**), Rosebud (**RBD**) and Sorrento (**STO**) 66/22 kV zone substations. These three zone substations together with other zone substations in the region including Frankston South (**FSH**), Hastings (**HGS**) and Mornington (**MTN**) are supplied from the 220/66 kV transmission connection point known as Tyabb Terminal Station (**TBTS**), the sole source of electricity supply to the Mornington Peninsula from the Victorian shared transmission network.

8.2.1 NETWORK LIMITATION

The 66kV sub-transmission network which supplies this region is relatively long with the transmission connection point located on the eastern side of the Mornington Peninsula and most of the load centres located on the west side. This sub-transmission network is also highly utilised at times of maximum demand. In the 2015 maximum demand forecast, it was estimated that five sub-transmission lines, which provide electricity supply to the region, will have maximum demands that exceed their respective N-1 thermal ratings.

The other more pressing issue is the inability of the network to maintain voltage levels within regulatory limits in the event of an outage of either the MTN-DMA 66kV line or the TBTS-DMA 66 kV line at high demand conditions, with the former being the more severe condition.

8.2.2 PROPOSED NETWORK OPTION

Given the relatively long distance of existing zone substations and the load centres from the transmission connection point in this region, all credible network options are relatively expensive to implement. UE identified two potential credible network options that were technically comparable to address the identified need:

Network Option	Description
Network Option 1	<p>Install a new 66 kV line between Hastings and Rosebud zone substations</p> <p>This option includes:</p> <ul style="list-style-type: none"> Installing approximately 53 km of new 66 kV line from Hastings (HGS) zone substation to Rosebud (RBD) zone substation. The new line would be constructed along the south-eastern coast (along the road reserve) of the Mornington Peninsula. Most of the route would involve the reconstruction of existing overhead pole lines. Installing three 66 kV circuit breakers, one at RBD and two at HGS zone substations. Upgrade the TBTS-HGS No.1 and No.2 feeder exits at Tyabb Terminal Station (TBTS). <p>The estimated capital cost of this option is 29.5 million ($\pm 10\%$) in 2015-16 AUD. Annual operating and maintenance costs are anticipated to be around 0.5% of the capital cost.</p> <p>The implementation date for this option is before summer 2020-21 to maximise the net economic benefit.</p>

8.2.3 PROPOSED NON-NETWORK OPTION

In November 2014, UE commenced the RIT-D consultation process to seek alternative options in addressing the need to the proposed network option.

In response to this consultation, UE received two detailed proposals from GreenSync Pty Ltd and Aggreko Pty Ltd proposing alternative ways to address the need in the lower Mornington Peninsula supply area.

From the two submissions received, UE identified one credible network option and two credible hybrid options (comprising of non-network solutions followed by a deferred network option) that are technically comparable in addressing the identified need. The three credible options identified to undergo RIT-D assessment were:

Table 3 – Credible options considered in the RIT-D assessment

RIT-D Option	Description
Option 1	As described in Section 8.2.2.
Option 2	<p>This option is a hybrid of a non-network solution and network investment project.</p> <p>Stage 1 – Implement GreenSync four year non-network demand reduction solution before summer 2018-19 to defer network investment (as described in Option 1 above) by two years to address the identified need at an estimated capital cost of 3.67 million in 2015-16 AUD.</p> <p>Stage 2 - Second stage of this option is to implement network option (as described in Option 1 above) by December 2022 at an estimated capital cost of 29.5 million ($\pm 10\%$) in 2015-16 AUD to maximise the net economic benefit.</p> <p>Total cost</p> <p>The estimated total cost (Stage 1 + Stage 2) of this option is 35.0 million in 2015-16 AUD.</p>
Option 3	<p>This option is also a hybrid of a non-network solution and network investment project.</p> <p>Stage 1 – Implement Aggreko five year non-network embedded generation solution before summer 2019-20 to defer network investment (as described in Option 1 above) by four years to address the identified need at an estimated capital cost of 9.65 million in 2015-16 AUD.</p> <p>Stage 2 – Second stage of this option is to implement network option (as described in Option 1 above) by December 2024 at an estimated capital cost of 29.5 million ($\pm 10\%$) in 2015-16 AUD to maximise the net economic benefit.</p> <p>Total cost</p> <p>The estimated total cost (Stage 1 + Stage 2) of this option is 40.6 million in 2015-16 AUD.</p>

On 16 December 2015, UE published the DPAR in accordance with clause 5.17.4(j) of the NER. The purpose of this report was to provide a basis for consultation on the proposed preferred option to address the network limitations within the lower Mornington Peninsula supply area. This report stated that the recommended action would involve the implementation of GreenSync's four year demand management solution from summer 2018-19, followed by a deferred network investment before December 2022.

Registered participants and interested parties were once again invited to lodge submissions on the matters outlined in the DPAR by 2 February 2016.

No submissions were received.

8.2.4 PREFERRED OPTION

UE defined a number of reasonable scenarios to test the robustness of this RIT-D assessment: the 'base case' (or the most likely scenario), and several other scenarios which represent plausible combination of upper and lower bound assumptions on the key variables of demand growth, investment cost, value of customer reliability and discount rate. Based on the economic assessment, Option 2 satisfied the requirements of the RIT-D and was therefore identified as the Preferred Option.

Table 4 - Net market benefits of each credible option, under base case reasonable scenario (PV, \$m)

RIT-D Option	Total capital, operating and maintenance costs	Total market benefits	Net economic benefit	Ranking under RIT-D
Do Nothing	0	0	0	4
Option 1	22.90	54.77	31.87	2
Option 2	23.07	55.21	32.14	1
Option 3	24.52	54.33	29.81	3

The stream of market benefits captured by the preferred non-network option included:

1. Reduction in involuntary load shedding and customer interruptions that is forecast to occur following the loss of any sub-transmission line.
2. Difference in PV Cost achieved due to the deferral of Network Capex project due to implementation of a credible non-network solution.
3. Reduction in electrical energy losses.

UE conducted a detailed risk assessment of the preferred non-network solution.

UE published the FPAR on 30th June 2016 to conclude the RIT-D process. A Network Support Agreement is now in place with the non-network service provider from summer 2018/19 to summer 21/22.

8.3 EXAMPLE 3 - NOTTING HILL SUPPLY AREA RIT-D

Notting Hill (**NO**) zone substation was commissioned in the late 1960s, as a two-transformer zone substation to provide capacity to the growing Notting Hill, Springvale and Clayton supply areas. This region has developed over time into a flourishing commercial and educational precinct with ongoing development and further growth opportunities.

8.3.1 NETWORK LIMITATION

The following limitations were to be addressed by the RIT-D:

- From summer 2016-17, inadequate load transfer capability between NO and the neighbouring network is expected to lead to supply interruption, following the loss of a transformer at NO zone substation during very high demand periods;
- There will be an increase in energy-at-risk in the neighbouring zone substations and distribution network, following load transfers from NO; and
- The maximum loading of a number of distribution feeders in the NO, Clarinda (**CDA**), Springvale West (**SVW**) and Glen Waverley (**GW**) supply areas are forecast to exceed their thermal capability within the next five years under system normal operation. Losing highly utilised NO feeders during a period of high demand will lead to supply interruption for some customers.

8.3.2 PROPOSED NETWORK OPTION

UE presented five network options in the NNOR. Three of these options were regarded as not being credible for reasons set out in that paper. Furthermore, one of the credible options detailed in the NNOR has been assessed as a higher cost option and not attracting enough market benefits. Therefore only one credible network option presented in the NNOR has been assessed as part of this RIT-D.

Table 5 – Credible options considered in the RIT-D

Option	Description
1 Network Augmentation	<p>Third transformer at Notting Hill zone substation and two new distribution feeders</p> <p>This option includes:</p> <ul style="list-style-type: none"> • Installing a new 20/33 MVA 66/22 kV transformer at Notting Hill zone substation. • Installing a new 66kV bus tie circuit breaker • Installing a Neutral Earthing Resistor (NER) • Extending the 22 kV busbar at Notting Hill zone substation. • Developing two new 22 kV distribution feeders to supply the loads in and around Notting Hill area. <p>This option will:</p> <ul style="list-style-type: none"> • Eliminate the risk of supply interruption following the loss of one of the two Notting Hill zone substation transformers. • Eliminate the risk of supply interruptions from distribution feeders exceeding their rating under system normal conditions. • Reduce the risk of supply interruptions for loss of a distribution feeder. <p>The estimated capital cost of this option is \$ 5.07 million ($\pm 10\%$), in 2016-17 \$AUD. Annual operating and maintenance costs are anticipated to be around 0.5% of the capital cost.</p> <p>The estimated commissioning date is December 2017.</p> <p>The estimated total annual cost of the Preferred Network Option is \$ 322,513.</p>

8.3.3 PROPOSED NON NETWORK OPTION

In April 2016, UE commenced the RIT-D consultation process to seek alternative options in addressing the need to the proposed network option.

In response to this consultation, UE received one detailed proposal from Energy Developments Pty Ltd (**EDL**) proposing an alternative way to address the need in the Notting Hill supply area. UE also received a response from Clean Technology Partners indicating that they will not be submitting a non-network solution proposal for this particular limitation.

UE identified three credible options that are technically comparable in addressing the identified need – one Network option as published in the NNOR and two credible hybrid options comprising of a Non-network solution and the deferred Network option. The three credible options identified are:

Table 6 – Credible options considered in the RIT-D

Option	Description
1 Network Augmentation	As described in Section 8.1.2.
2 EDL + Network Aug	<p>EDL non-network solution followed by deferred Option 1</p> <p>This option is a hybrid of a non-network solution and network investment project.</p> <p>Stage 1 - EDL non-network solution</p> <p>The EDL demand management proposal defers network investment (as described in Option 1 above) by 1-year to address the identified need.</p> <p>This option includes:</p> <ul style="list-style-type: none"> Contracting EDL to provide demand management at NO, SV and SVW supply areas until commissioning of network project (as described in Option 1 above). Utilising embedded generation and the load transfer capability through the Monash University 22kV bus and providing demand side management by integrating University Building Automation System (BAS). Pre-contingent and Post Contingent load relief for NO Zone Substation. Establishment cost components for a 1-year proposal is 0.33 million in 2016-17 \$AUD Capacity cost (\$ 10 per kW - weighted average) Dispatch cost (\$ 1,000 per dispatch day) <p>The estimated capital cost of Stage 1 of this option is \$ 0.37 million in 2016-17 \$AUD.</p> <p>The estimated commissioning date for Stage 1 is December 2017</p> <p>Stage 2 - Install third transformer at Notting Hill zone substation and two new distribution feeders</p> <p>Second stage of this option is to implement network project by December 2018 which includes:</p> <ul style="list-style-type: none"> Installing a new 20/33 MVA 66/22 kV transformer at Notting Hill zone substation. Installing a new 66kV bus tie circuit breaker Installing a Neutral Earthing Resistor (NER) Extending the 22 kV busbar at Notting Hill zone substation. Developing two new 22 kV distribution feeders to supply the loads in and around Notting Hill area. <p>The estimated capital cost of Stage 2 is \$ 5.07 million ($\pm 10\%$) in 2016-17 \$AUD. Annual operating and maintenance costs are anticipated to be around 0.5% of the capital cost.</p> <p>The implementation date for this stage is before summer 2018-19 to maximise the net economic benefit.</p> <p>Total cost</p> <p>The estimated total cost (Stage 1 + Stage 2) of this option is \$ 5.9 million in 2016-17 \$AUD.</p>
3 EDL & 2FDR+ Network Aug	<p>Split Option 1 into two parts Option 1a and 1b. Implement EDL non-network solution in conjunction with Option 1a followed by deferred Option 1b</p> <p>This option is a hybrid of a non-network solution and network investment project.</p> <p>Stage 1 - EDL non-network solution and two new distribution feeders (Option 1a)</p>

	<p>The EDL demand management proposal defers network investment (as described in Option 1 above) by 4-years to address the identified need.</p> <p>This option includes:</p> <ul style="list-style-type: none"> • Contracting EDL to provide demand management at NO, SV and SVW supply areas until commissioning of complete network project (as described in Option 1 above). • Utilising embedded generation and the load transfer capability through the Monash University 22kV bus and providing demand side management by integrating University Building Automation System (BAS). • Pre-contingent and Post Contingent load relief for NO Zone Substation. • Establishment cost components for a 4-year proposal is \$ 0.43 million in 2016-17 \$AUD • Capacity cost (\$ 10 per kW - weighted average of 4-years) • Dispatch cost (\$ 1,000 per dispatch day) • Extending the 22 kV busbar at Notting Hill zone substation. • Developing two new 22 kV distribution feeders to supply the existing loads in and around Notting Hill area. <p>The estimated capital cost of Stage 1 of this option is \$ 2.47 million in 2016-17 \$AUD.</p> <p>The estimated commissioning date for Stage 1 is December 2017.</p> <p>Stage 2 - Install third transformer at Notting Hill zone substation (Option 1b)</p> <p>Second stage of this option is to implement Part 1b of the network project by December 2021, which includes:</p> <ul style="list-style-type: none"> • Installing a new 20/33 MVA 66/22 kV transformer at Notting Hill zone substation. • Installing a new 66kV bus tie circuit breaker • Installing a Neutral Earthing Resistor (NER) <p>The estimated capital cost of Stage 2 is \$ 3.7 million ($\pm 10\%$) in 2016-17 \$AUD. Annual operating and maintenance costs are anticipated to be around 0.5% of the capital cost.</p> <p>The implementation date for this stage is before summer 2021-22 to maximise the net economic benefit.</p> <p>Total cost</p> <p>The estimated total cost (Stage 1 + Stage 2) of this option is \$ 6.1 million in 2016-17 \$AUD.</p>
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8.3.4 PREFERRED OPTION

The table below summarise the net market benefit in NPV terms for each credible option. The net market benefit is the gross market benefit, under the base case reasonable scenario, minus the total capital, operating and maintenance cost of each option, all in present value terms.

The table also shows the corresponding ranking of each option under the RIT-D.

Table 7 – Net market benefits of each credible option, under base case reasonable scenario (PV, \$m)

Options	Cost			Market Benefits	Net Economic Benefit	Ranking under RIT-D
	Network	Non-Network	Total			
Do Nothing			0	0	0	4
Option 1	4.99	-	4.99	13.90	8.91	1
Option 2	4.69	0.35	5.04	13.71	8.67	3
Option 3	4.36	0.47	4.83	13.64	8.81	2

The table above shows that all credible options considered have a positive net market benefit, in the form of large reductions in involuntary load shedding (unserved energy). As a consequence, all three options are ranked higher than the 'Do Nothing' option, and could be expected to result in an overall net economic benefit to the market.

This RIT-D assessment demonstrates that Option 1 - Network Augmentation has the highest net economic benefit under the base case reasonable scenario. This RIT-D assessment also demonstrated (through sensitivity analysis on key variables such as discount rate, investment cost, Value of customer reliability, and demand forecast), that Option 1 maximises the present value of net market benefits under all reasonable scenarios considered. Option 1 was therefore identified as the preferred option.

Therefore UE published the FPAR on 14th December 2016 to conclude the RIT-D process.

8.4 EXAMPLE 4 - DONCASTER HILL DISTRICT ENERGY SERVICES SCHEME

8.4.1 NETWORK LIMITATION

Doncaster (DC) zone substation is fully developed with two 20/27 MVA 66/22 kV transformers and one 20/30 MVA 66/22 kV transformer and supplies the areas of Box Hill Central, Box Hill North, Doncaster, Doncaster East, Doncaster Hill and The Pines precincts, and Templestowe. Being designated Principal Activities Centres, the maximum demand in the Doncaster Hill and Box Hill areas is expected to continue to grow steadily over coming years.

The maximum summer demand of the substation is already above its (N-1) rating with the exception of summer 2011-12 and 2014-15, and the maximum demand is expected to continue to increase by at least 1 to 2MW per annum for the foreseeable future. With major commercial and high density residential developments occurring in the Doncaster Hill area, there is a need later this decade to augment the network to offload or reinforce the Doncaster zone substation, thereby providing additional capacity for the Doncaster Hill area. The 2015 DAPR identified that non-network solutions in the order of 2.0MVA between the hours of 15:00 to 20:00 on maximum demand days, will help defer the need for network augmentation.

8.4.2 PROPOSED NETWORK OPTION

UE has identified two likely network options to resolve the network limitations at Doncaster zone substation. Either establishing a 4th transformer at the existing Doncaster zone substation with associated sub-transmission and distribution feeder upgrades, or establishing a new 66/22kV zone substation in Templestowe. Templestowe was identified as a suitable locality for a new zone



substation to offload Doncaster because it allows the distribution feeder lengths to be cut in half, effectively doubling the supply reliability for the area and significantly reducing expected energy at risk at Doncaster zone substation and the sub-transmission loops in the area. Accordingly, in 2012, UE purchased a site in Templestowe for this new zone substation.

8.4.3 PROPOSED NON-NETWORK OPTION

DMIA funding has been used to explore options with Council to manage maximum demand and potentially defer planned network augmentation. The joint planning identified a commercially viable non-network solution in the form of a District Energy Services Scheme (**DESS**) for Doncaster Hill.

In 2012, UE and Council used DMIA funding to engage two District Energy Service Providers to undertake a commercial feasibility study into a DESS in Doncaster Hill with an objective to defer the planned network augmentation at Doncaster zone substation. Both Service Providers concluded that such a scheme was commercially viable.

8.4.4 PREFERRED OPTION

Following a detailed verification review of both providers' proposals in 2013, the Council identified a preferred provider for a DESS for the Doncaster Hill Principal Activities Area. While this opportunity did not end up resulting in a commercial solution, it did identify that non-network solution may be possible in the area. As such UE plans to continue to facilitate opportunities to develop non-network solutions in the area in the lead-up to the future RIT-D to maximise the opportunity for a viable, competitive non-network solution to defer the planned network augmentation and address this emerging network limitation.

9 Enquiries and submissions

UE welcomes any enquiries or written submissions from registered and interested parties on proposed network investments identified in UE's DAPR or during the RIT-D process. We also welcome opportunities for joint planning initiatives or establishing projects under the DMIA which may lead to non-network solutions on UE's network.

All enquiries and submissions should be directed to UE's Manager Network Planning & Strategy at planning@ue.com.au. Alternatively, UE's postal address for enquiries and submissions is:

United Energy

Attention: Manager Network Planning & Strategy

PO Box 449

Mt Waverley VIC 3149



10 Appendix A: Avoided TUoS

This appendix sets out the current policy for UE in calculating avoided TUoS payments for embedded generators.

10.1 WHAT IS AVOIDED TUOS?

Avoided TUoS payments are paid to embedded generators to compensate embedded generators for connecting directly to the distribution network, allowing transmission businesses to avoid capital expenditure costs.

10.2 COMPONENTS IN CALCULATION

Clause 5.5(h) of the NER states that the avoided TUoS payment is for the avoided charges for the locational component of prescribed TUoS services.

10.3 AVOIDED TUOS CALCULATIONS FOR A SINGLE GENERATOR

The following process outlines the method that UE uses to calculate avoided TUoS:

Step 1 – Determine calculation period

The calculation period, t , is the recently completed 12 month period ($t-1$) spanning 1 March to 28 February between the hours 11:00 and 19:00 (local time).

Step 2 – Collect Data

Interval meter data, i , must be available for the period. Interval meter readings are taken every 15 minutes for terminal stations and embedded generators. This is converted to 30 minute interval data (average of two 15 minute intervals) for use, k .

Variables:

t : Most recent 12 month period covering 1 March to 28 February represented in the Avoided TUoS calculation

i : Set of interval data

j : Sub-set of interval data over period t for 11am to 7pm (local time) weekdays

k : Period of time in minutes converted for use between interval readings

Not all interval data is used in the avoided TUoS calculation. The variable j is a subset of i that only includes data recorded between 11am and 7pm (local time) on weekdays. This is consistent with AEMO's criterion for selecting 10 maximum demand days for the purposes of allocating locational TUoS revenue to the connection points, as reflected in AEMO's pricing methodology.²⁰

²⁰ AEMO, *Approved amended pricing methodology for prescribed shared transmission services for 1 July 2014 to 30 June 2019*, 15 May 2015, https://www.aer.gov.au/system/files/AEMO%20-%20Approved%20amended%20pricing%20methodology%20-%201%20July%202015%20to%2030%20June%202019_0.pdf

Step 3 – Calculate the new maximum demand (MD) had the generator not injected any energy

a) Apportionment of Energy

For the purposes of calculating avoided TUoS the energy produced by the embedded generator must be allocated to one or more terminal stations.

Where the embedded generator is connected to the distribution network in a location wholly serviced by one terminal station, all energy delivered by the embedded generator will be allocated to that terminal station. Where the embedded generator is connected to the distribution network in a location that is serviced by multiple terminal stations the energy will be apportioned between the terminal stations in accordance with the appropriate engineering calculations.

Calculations are to be determined such that:

$$\sum_{m=1}^n p_m = 1$$

where:

p : proportion of energy to be assigned to each terminal station

n : number of terminal stations linked to the embedded generator

m : terminal station

b) Calculate the MD including the embedded generator (MD10')

For each terminal station, m , and for each set of interval data, j , the maximum demand including embedded generator impacts, MD10', will be calculated as follows:

$$MD'_{mj} = (r_{mj} + s_j \times p_m) \times 60/k$$

where;

MD'_{mj} : Maximum Demand for interval j at Terminal Station m

r_{mj} : Interval reading in MWh for interval j at Terminal Station m

s_j : Interval reading in MWh for interval j at the Embedded Generator

p_m : Proportion of energy allocated to Terminal Station m

The average of the set of 10 highest daily demand values, MD'_{mj} , will be the deemed maximum demand inclusive of embedded generator impacts, MD10', for the terminal station.

c) Calculate the Avoided Demand (Avoided TUoS)

The avoided demand, AD, is calculated by averaging the demand of embedded generation EG_{md} recorded on the same date and time of the 10 highest daily demand values of MD'_{mj} .

$$AD = \text{mean}(EG_{md10})$$

where:



EG_{md10} is the 10 demand values of embedded generator recorded at same date and time of MD'_{mj}

Step 5 – Calculate the Avoided TUoS Charge

For each terminal station, avoided demand, $aMD10_m$, will be multiplied by the usage rate, R , applicable to the terminal station, m . Usage rates are published by AEMO for each summer period. Avoided TUoS (the "**Avoided TUoS Amount**") for each terminal station will be summated to give the total avoided TUoS for the embedded generator.

$$AvoidedTUoS = \sum_{m=1}^n aMD10_m \times R_m$$

where;

R_m : Usage rate in dollars for Terminal Station m for the period t

Step 6 – Avoided TUoS Shared Benefit

In some cases, contractual agreements may exist for sharing of avoided TUoS payments. Where such arrangements exist the avoided TUoS amount will be apportioned as specified by the contract.

11 Appendix B: Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DAPR	Distribution Annual Planning Report
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DPAR	Draft Project Assessment Report
DSED	Demand Side Engagement Document
DSPR	Distribution System Planning Report
FPAR	Final Project Assessment Report
MoU	Memorandum of Understanding
NEM	National Electricity Market
NER	National Electricity Rules
NNOR	Non-Network Options Report
NPV	Net Present Value
NSA	Network Support Agreement
RIT-D	Regulatory Investment Test for Distribution
TUoS	Transmission Use of System
UE	United Energy
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital



12 Appendix C: Glossary

Credible option	An option that: <ul style="list-style-type: none">• Addresses the identified 'need';• Is commercially and technically feasible; and• Can be implemented in sufficient time to meet the identified 'need'.
Expected Energy at Risk	The expected amount of energy that cannot be supplied each year because there is insufficient capacity to meet demand, taking into account equipment unavailability and load at risk.
Identified 'need'	Any capacity or voltage limitation on the distribution system that will give rise to Expected Energy at Risk.
Network option	A means by which an identified 'need' can be fully or partly addressed by expenditure on the distribution asset.
Non-network option	A means by which an identified 'need' can be fully or partially addressed other than by a network option.
Non-network service provider	A party who provides a non-network option
Potential credible option	An option has the potential to be a credible option based on an initial assessment of the identified 'need'.
Preferred option	A credible option that maximise the present value of net economic benefit to all those who produce, consume and transport electricity in the market. The preferred option can be a network option, non-network option, or do nothing (i.e. status quo).
Value of customer reliability	The value customer places on having a reliable supply of energy, which is equivalent to the cost to the customer of having that supply interrupted expressed in \$/MWh.

13 Appendix D: NER Schedule Cross-References

Schedule 5.9 clause	Matters addressed	Section No.
5.9(a)	a description of how the Distribution Network Service Provider will investigate, develop, assess and report on potential non-network options	Section 5
5.9(b)	a description of the Distribution Network Service Provider's 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	Section 5
5.9(c)	an outline of the process followed by the Distribution Network Service Provider when negotiating with non-network providers to further develop a potential non-network option	Section 5
5.9(d)	an outline of the information a non-network provider is to include in a non-network proposal, including, where possible, an example of a best practice non-network proposal	Section 6
5.9(e)	an outline of the criteria that will be applied by the Distribution Network Service Provider in evaluating non-network proposals	Section 6.2
5.9(f)	an outline of the principles that the Distribution Network Service Provider considers in developing the payment levels for non-network options	Section 6.1
5.9(g)	a reference to any applicable incentive payment schemes for the implementation of non-network options and whether any specific criteria is applied by the Distribution Network Service Provider in its application and assessment of the scheme	Section 7
5.9(h)	the methodology to be used for determining avoided Customer TUoS charges, in accordance with clauses 5.4AA and 5.5; and	Section 7.1.1
5.9(i)	a summary of the factors the Distribution Network Service Provider takes into account when negotiating connection agreements with Embedded Generators	Section 5.2.3

5.9(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	Section 5.2.3
5.9(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	Section 5.2.3
5.9(l)	worked examples to support the description of how the Distribution Network Service Provider will assess potential non-network options in accordance with paragraph (a)	Section 8
5.9(m)	a hyperlink to any relevant, publicly available information produced by the Distribution Network Service Provider	Section 5.1.1 Section 5.2.3 Section 7.1.3
5.9(n)	a description of how parties may be listed on the demand side engagement register; and	Section 3.3
5.9(o)	the Distribution Network Service Provider's contact details	Section 9










UE PL 2202 Demand Side Engagement Document

Final Audit Report

2019-07-05

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