CitiPower Pty Ltd/

Powercor Australia Ltd

DEMAND SIDE ENGAGEMENT STRATEGY

30 July 2019

V3.1

Version Control

Version	Date	Updated by	Comments
1.0	31 August 2013	Electricity Networks	New document
2.0	25 July 2016	Electricity Networks	Updated document
3.1	30 July 2019	Electricity Networks	Updated document

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1 Overview

CitiPower Pty Ltd (**CitiPower**) and Powercor Australia Ltd (**Powercor**) have provided this Demand Side Engagement Strategy to assist non-network providers in understanding our framework and processes for assessing demand side options. This engagement strategy also discusses our consultation process with non-network providers.

As consumers generally continue to require more electricity to meet their needs, non-network providers are having an increasingly important role in the supply of electricity. Where technically feasible and economic, non-network options can help to address localised constraints in the network and thus defer network augmentation. As such, non-network options have the potential to meet rising demand at a lower cost to consumers.

This engagement strategy provides information on how CitiPower and Powercor will engage with non-network providers and how it will consider non-network options. It is aligned with the requirements of clauses 5.13.1(e) to (j) of the National Electricity Rules (**NER**) and contains the detailed information set out in Schedule 5.9 of the NER.

CitiPower and Powercor will review this engagement strategy at least once every three years.

2 Introduction

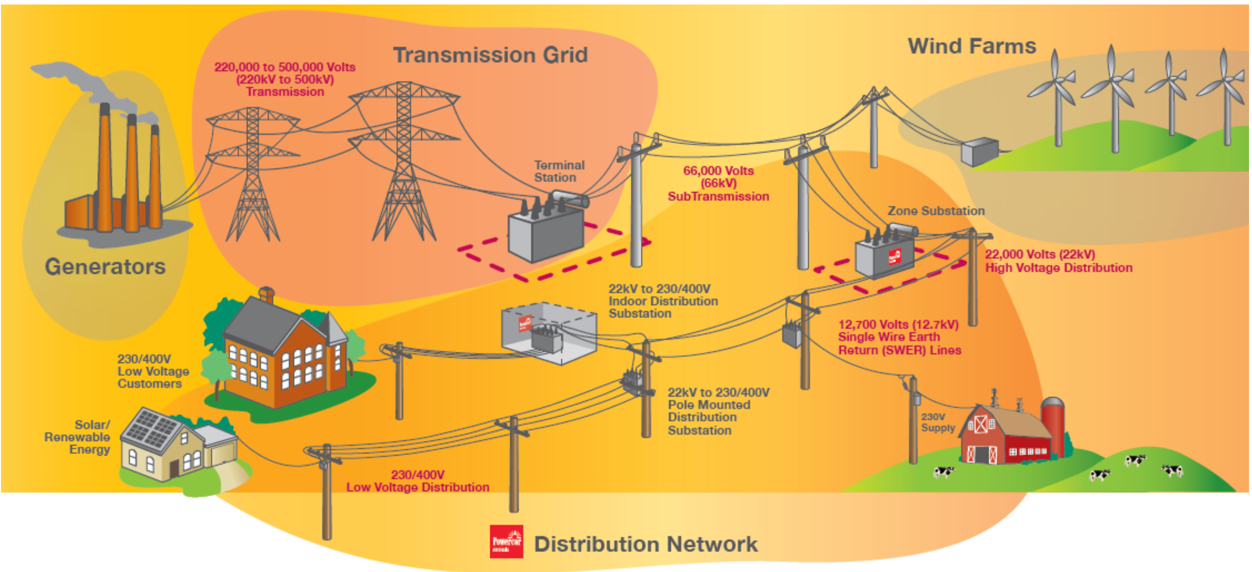
This chapter sets out background information on CitiPower and Powercor and how it fits into the electricity supply chain.

2.1 Who we are

CitiPower Pty Ltd (**CitiPower**) and Powercor Australia Ltd (**Powercor**) are regulated Distribution Network Service Providers (**DNSPs**) within Victoria. CitiPower and Powercor own 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 2.1: 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 and Powercor convert electricity from the transmission network into high and low 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. CitiPower and Powercor are two of those distribution businesses.

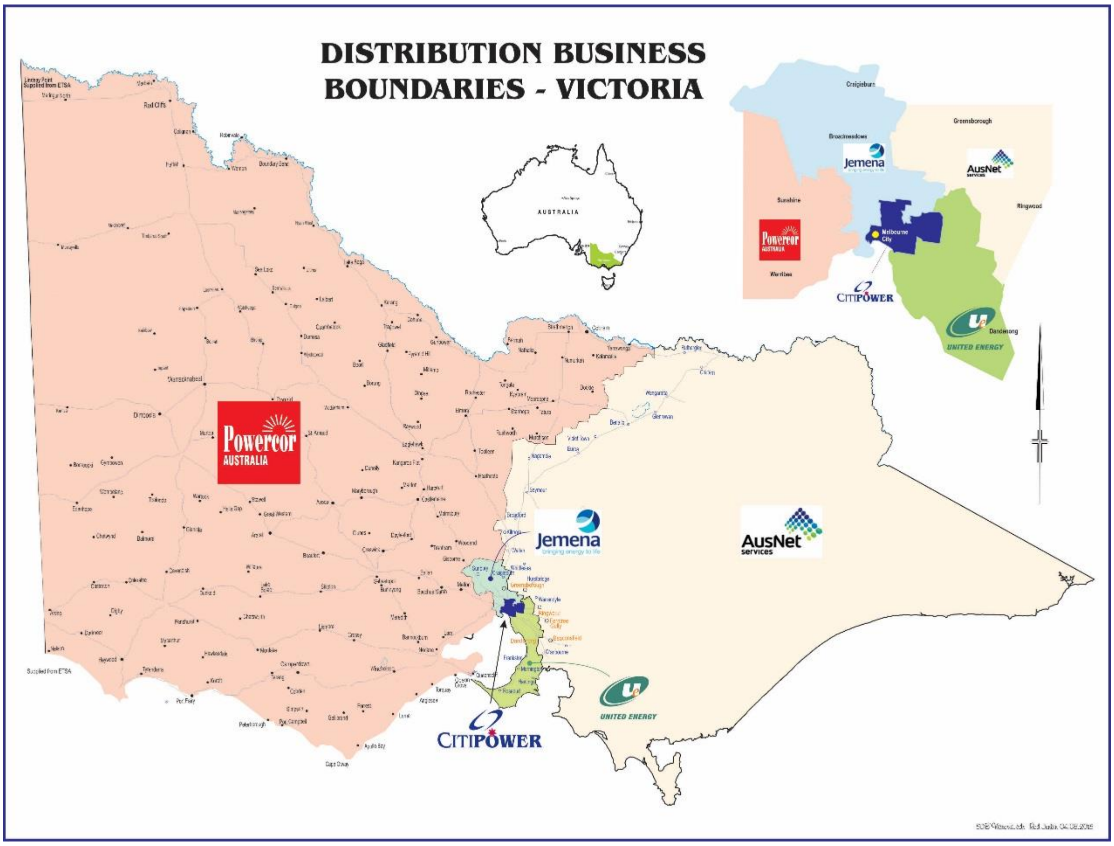
The distribution areas for CitiPower and Powercor are as follows:

- CitiPower: provides electricity to customers in Melbourne's central business district and inner suburbs, and supplies world-class cultural and sporting facilities such as Federation Square, the Melbourne Cricket Ground, the Victorian Arts Centre and Melbourne Park.

- Powercor: provides electricity to customers in central and western Victoria as well as Melbourne's outer western suburbs. It is the largest of Victoria's five electricity distribution networks, and supplies key regional centres from Mildura and Shepparton through Bendigo and Ballarat to Warrnambool and Geelong.

The coverage of all distribution networks in Victoria is shown in Figure 2.2 below.

Figure 2.2: Victorian distribution businesses



3 Non-network alternatives

Historically, CitiPower and Powercor have built new electricity infrastructure to meet the increasing demand for electricity by customers. This may involve augmentation of the network by, for example, installing a new transformer at a terminal station and building new powerlines on new or existing power poles. These are generally referred to as *'network solutions'*.

The construction and maintenance of these assets may be expensive, and more economical non-network options may exist. Such non-network options may be temporary or permanent, and may defer or replace the building of a network solution.

This chapter sets out when peak demand generally occurs for CitiPower and Powercor, and how non-network options can assist in addressing that peak demand at a localised level.

3.1 Peak demand of the distribution network

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

CitiPower and Powercor plan the network to cater for the expected level of peak demand. Our forecasting and planning processes take into account a number of factors including statistical temperature forecasts, new connections, usage patterns and economic factors to estimate the required capacity of the network.

When forecast peak demand approaches the existing capacity of the network infrastructure at a given location, CitiPower/ Powercor may be required to revise their network plans to ensure that customer demand continues to be met. Increased demand can be managed through either:

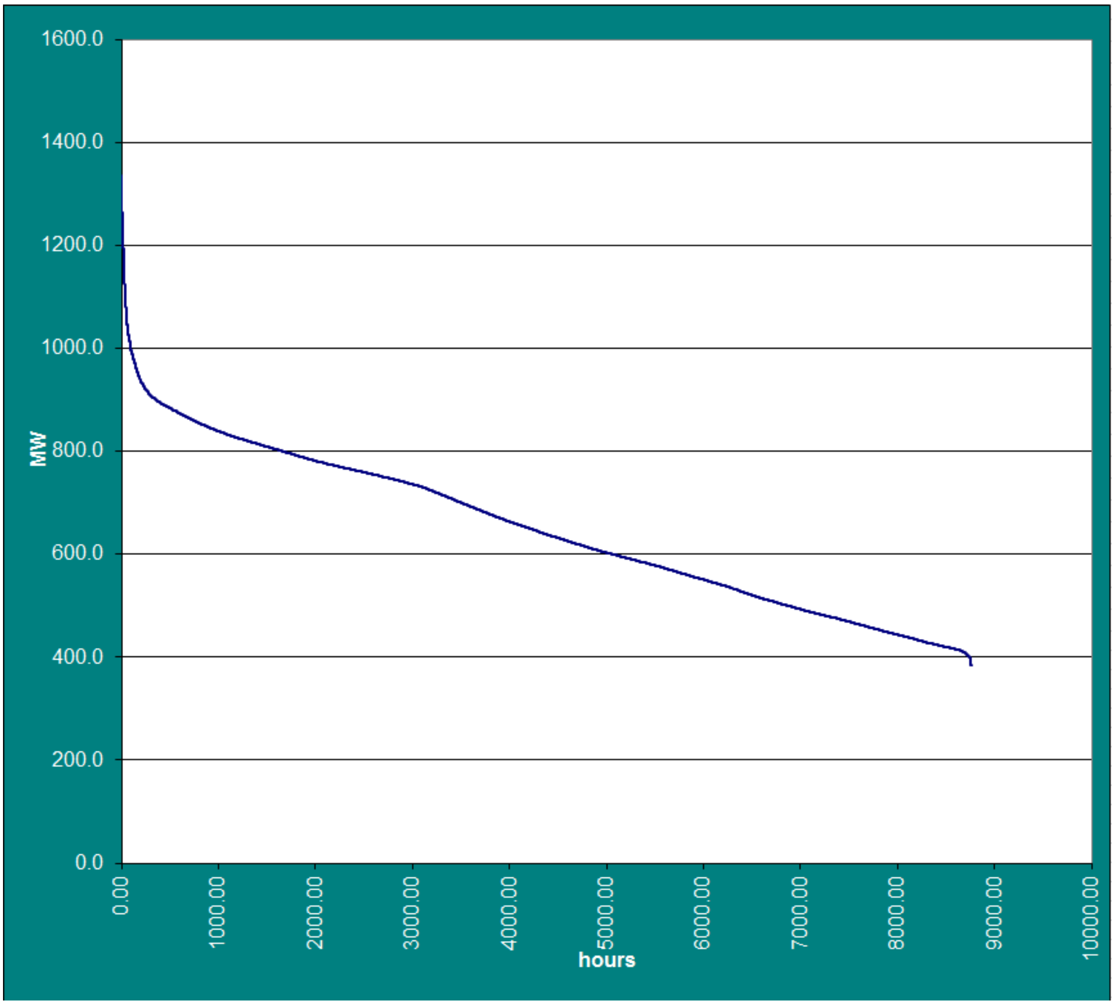
- increasing the network's capacity;
- use of new technology options such as embedded generators or storage (e.g. battery storage); or
- reducing the peak electricity demand on the network.

3.1.1 Frequency of peak demand

Peak demand typically occurs on five to eight days of the year, and for around five hours in total on each of those days. That is, peak demand occurs for approximately 40 hours a year, which is less than 0.5% of hours in a year. Therefore, in an area of the network that is already highly utilised, a non-network option which reduces demand for only these hours may offer a preferable alternative to constructing new network assets.

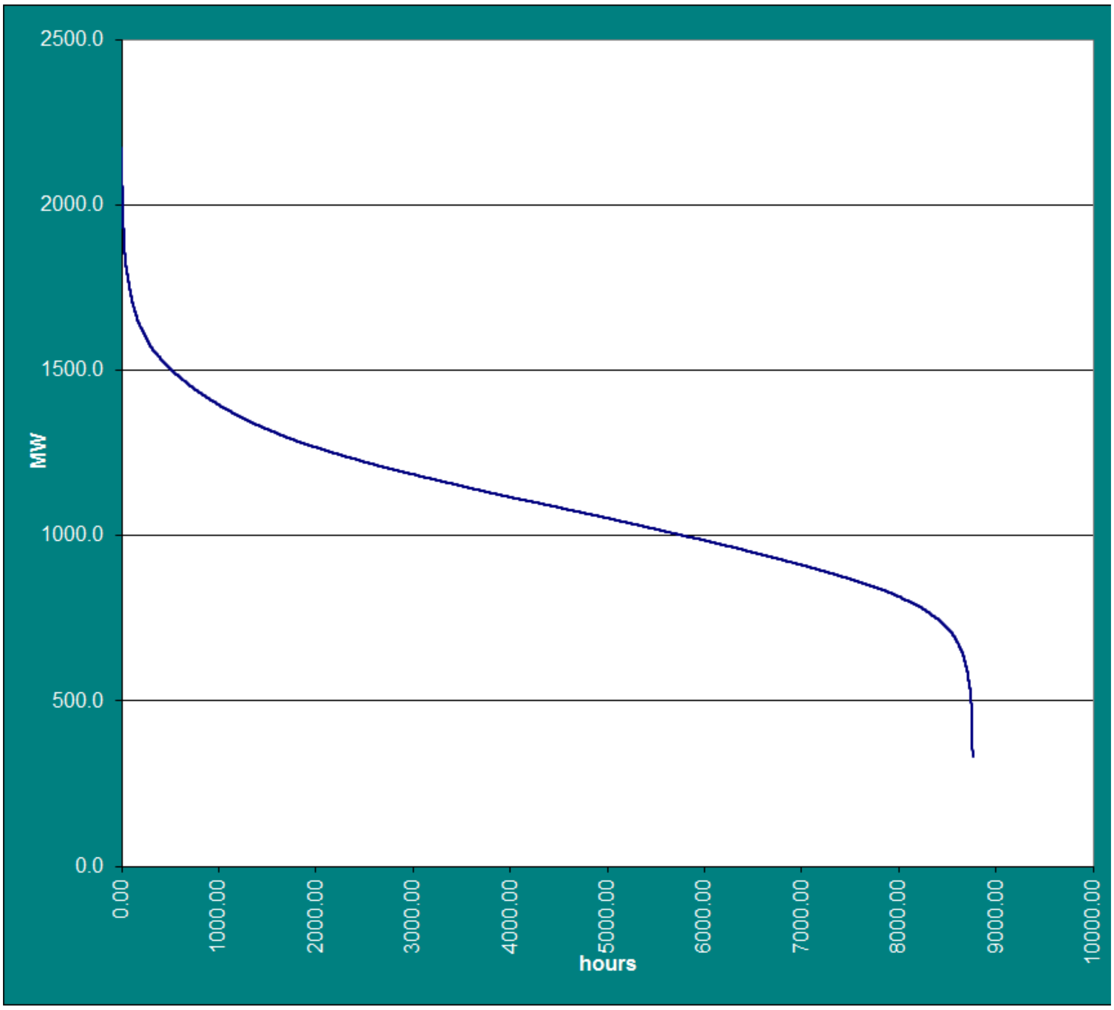
The graph below shows the peak load duration curve for CitiPower. This shows the relationship between the capacity requirements and capacity utilisation of the CitiPower network. The actual peak is 1444MW, which represents the sum of the coincident peak demand across all terminal stations in the CitiPower network.

Figure 3.1: CitiPower 2018 load duration curve



The graph below shows the overall peak load duration curve for Powercor. The actual peak is 2322MW.

Figure 3.2: Powercor 2018 load duration curve



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

3.1.2 Summer and winter peak demand

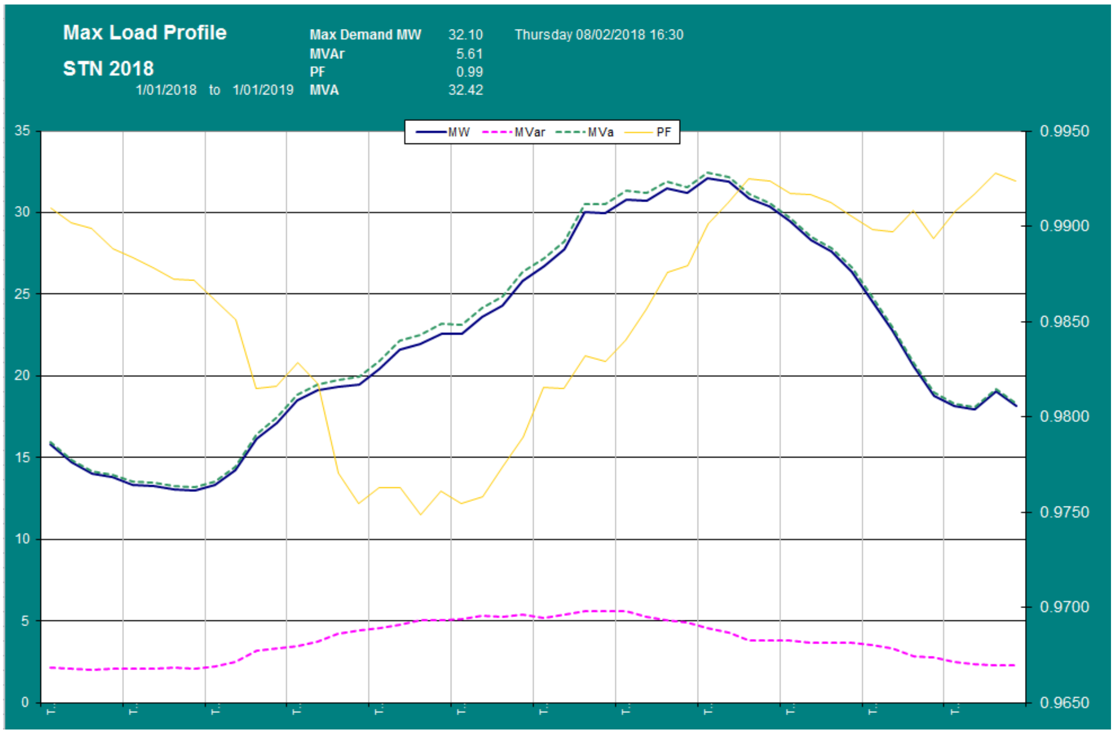
Peak demand can be either *'summer peaking'* or *'winter peaking',* and on occasion both summer and winter peaking. The timing of peak demand may differ between terminal stations and substations in the network, reflecting the electricity usage by customers at the local level.

Summer peaking normally occurs on the hottest working weekdays in summer. It can occur from as early as 2pm for commercial and industrial areas to as late as 8pm where demand from residential customers is influential.

Winter peaking occurs on the coldest working weekdays in winter and can occur from as early as 5pm to as late as 10pm.

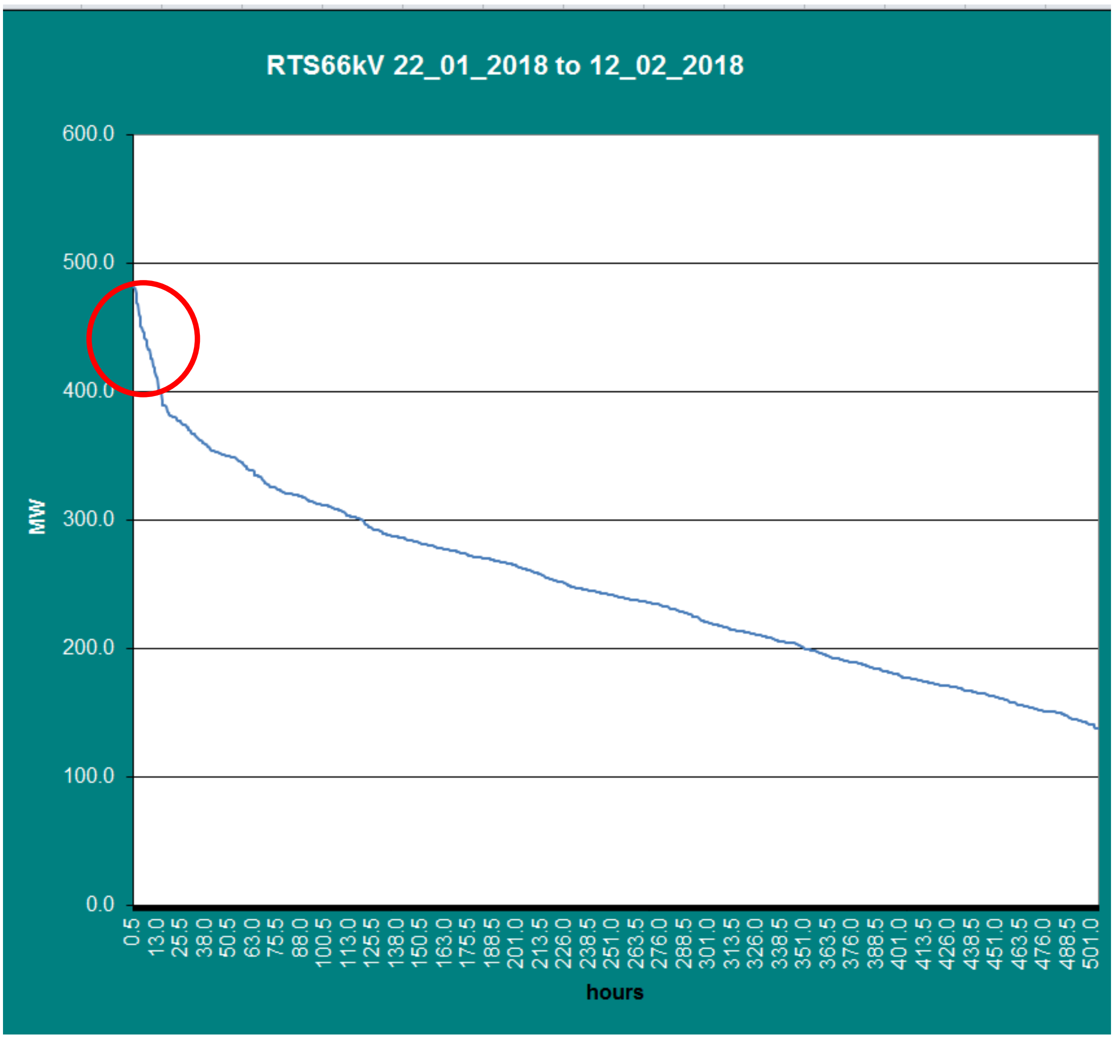
The figure below shows the daily electrical demand on a peak day for a typical summer peaking electricity substation, as typified by the Shepparton North Zone Substation on 08/02/18????

Figure 3.3: Maximum demand day at Shepparton North Zone Substation



Peak demand may occur for only a short duration in a given year. For example, in the area served by Richmond Terminal Station during the hottest three weeks of the 2018 year, the top 10 per cent of the demand only occurred for 10 hours. This is highlighted below.

Figure 3.4: Load duration curve Richmond Terminal Station for the hottest three weeks



The effective and prudent use of non-network options can address localised network constraints associated with peak demand, and thus may defer network augmentation.

3.2 Use of non-network providers

Non-network solutions are an important component for the effective operation of the network and can involve either the reduction of customer electricity demand at peak times or the direct supply of electricity at the distribution level.

Effective and prudent use of non-network solutions can reduce the need for network augmentation and associated maintenance costs resulting in lower electricity bills for consumers. Recently Asset Replacement projects and programs have also been subject to RIT D guidelines. Non network solutions could also conceivably replace or reduce the need to replace network assets.

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

- automated, contracted or voluntary demand management;
- shifting appliance or equipment use from peak periods to non-peak periods (e.g. controlled load (off-peak) water heating);
- operating appliances at lower power demand for short periods (e.g. air conditioner load control);
- converting the appliance energy source from electricity to an alternative (e.g. switching from electric to gas heating);
- use of energy efficiency programs;
- voluntary load curtailment by customers, such as in response to a request to reduce electricity usage;
- voluntary load shedding and disconnection of non-critical loads by customers;
- power factor correction of customer equipment;
- operation of embedded generators using conventional and renewable fuel sources;
- use of stand-by generators to enable load transfer; and
- storage devices such as batteries that can store energy in times of reduced demand and convert back to electricity at times of peak demand.

When a network constraint 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 that addresses the whole, identified need (noting that a non-network solution need not remove the entire constraint; rather, it may contribute to a broader solution). The next chapter discusses our process for finding this solution.

3.3 Demand side register

CitiPower and Powercor maintain registers for parties to notify their interest in being advised of developments relating to the planning and expansion of the networks.

The notification to parties will include information about publication of any non-network options paper and the Distribution Annual Planning Report, as well as any other relevant publications. CitiPower and Powercor will use this register not only to consult with interested parties, but also to determine the level of interest and ability to participate in the development process for the development of non-network options.

To register, please lodge your details through the following links:

- CitiPower: https://www.powercor.com.au/customers/demand-management
- Powercor: https://www.powercor.com.au/customers/demand-management/

4 Process for considering non-network options

This chapter sets out the process and consultation with non-network providers that CitiPower and Powercor will undertake when addressing a current or future constraint in the network.

There are two different processes for addressing network constraints. The process selected will depend upon the likely cost in addressing the whole, identified need:

- where the estimated capital cost of the most expensive potential credible option to address the constraint is likely to be more than $6 million, and the project does not meet the exceptions to the Regulatory Investment Test for Distribution (**RIT-D**), then the RIT-D process will be followed as outlined in the Australian Energy Regulator's (**AER**) guidelines; or

- where the estimated capital cost to address the constraint is likely to be less than $6 million, or the project meets the exceptions to the RIT-D, then a streamlined process will be adopted.

Each process is discussed in turn.

4.1 RIT-D process

In December 2018, the AER revised its application guidelines relating to the RIT-D process which provides details of the process that must be followed in addressing a network constraint where the estimated capital cost of the most expensive potential credible option exceeds $6 million. This threshold applies to new projects commenced after 1 January 2018.

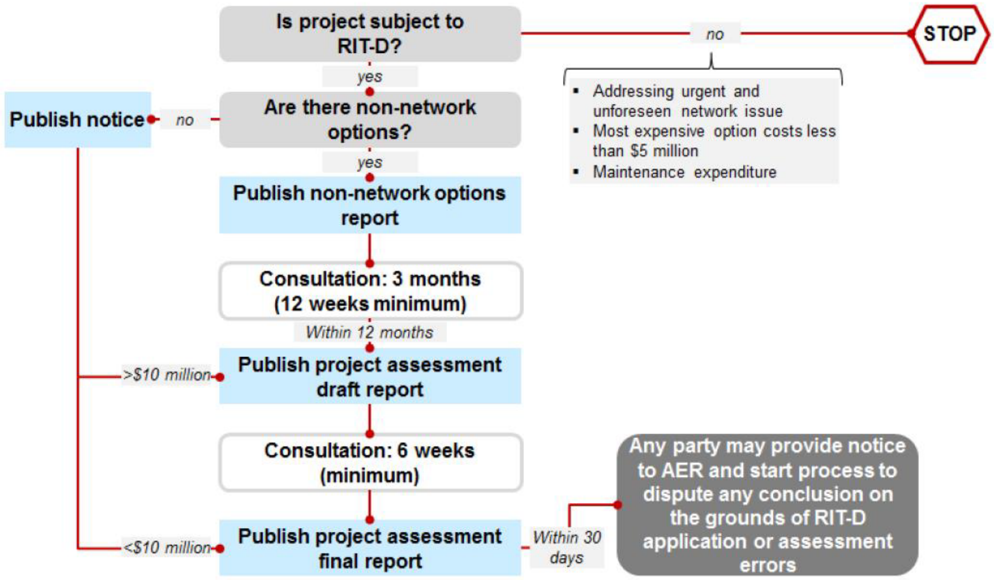
The application guidelines set out the process that CitiPower and Powercor must follow when applying the RIT-D as set out in the NER. At a high level, it consists of three stages:

- a Non-network Options Report;

- a Draft Project Assessment Report (**DPAR**) if the project is greater than $11 million; and

- a Final Project Assessment Report (**FPAR**). Note: If the project is less than $22 million the FPAR may form part of the DAPR (Distribution Annual Planning Report as published in December each year).

An overview of the process is provided in the diagram below, which has been extracted from the AER application guideline. Note that thresholds have since been updated as above.



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.

Figure 4.1: Process for projects requiring a RIT-D

Assessing possibilities

Once a current or future network constraint has been identified, a range of possible solutions will be considered to address that constraint. The options broadly encompass:

- network solutions, such as replacing or adding a new transformer and/or building new or replacing existing power lines; and/ or
- non-network solutions, including those referenced in section 3.2.

An initial assessment of the appropriateness of each option will be conducted. This will take into account the functionality of the network at the point of the constraint, and consider whether the solution addresses national and jurisdictional technical obligations. The technical analysis will also consider any impact of the potential option on other network users.

High level design work may be required for each possible option, which takes into account the appropriate equipment and standards that would have to be met. It may also take into account the relevant safety, regulatory and environmental considerations, and whether consent may be required from third parties.

In some cases, CitiPower/ Powercor may discuss a possible non-network option with one or more participants from its demand-side engagement register. This may assist in scoping out the appropriateness of the option and possible solution.

Where a non-network option is likely to address the network constraint (or form part of a solution that can address the constraint), be both technically and economically feasible and can be implemented in sufficient time, then CitiPower/ Powercor will prepare a Non-network Options Report. Otherwise, it will be determined that no non-network alternative is a potential credible option and CitiPower or Powercor will publish a notice under clause 5.17.4(d) of the NER setting out the reasons for making the determination, which includes the methodologies and assumptions used in making the decision.

4.1.1 Non-network Options Report

The process and requirements relating to the Non-network Options Report are set out clause 5.17.4(b) to (h) of the NER. The Non-network Options Report is required to contain:

- a description of the identified need;
- the assumptions used in identifying the identified need;
- the technical characteristics of the identified need that a non-network option would be required to deliver, such as:
  - the size of the load reduction or additional supply;
  - location;
  - contribution to power system security or reliability;
  - contribution to power system fault levels;
  - the operating profile; and
- a summary of potential credible options to address the identified need, including both network and non-network solutions.

Persons registered on the demand-side engagement register will be notified when the Non-network Options Report is published.

CitiPower/ Powercor will provide stakeholders with at least three months to comment on the Non-network Options Report.

4.1.2 Non-network proposals

In response to the Non-network Options Report, CitiPower/ Powercor will seek possible non-network providers to provide a proposal which discusses how their solution addresses, wholly or partially, the identified need.

Each non-network proposal should provide:

- overview of the objectives including the extent to which it addresses the identified need;
- technical description, including but not limited to:
  - location;
  - size of the load reduction or additional supply;
  - network connection requirements, if needed;
  - contribution to power system security or reliability;
  - contribution to power system fault levels;
  - the operating profile;
  - reliability;
  - how each of these matters is consistent with the technical standards and statutory requirements (guidance on these is available from the CitiPower and Powercor websites);
- timing of delivery of solution and its estimated lifespan;
- salvage and removal costs; and
- potential risks associated with the proposal and comparison with the risks associated with the deferred augmentation, and any actions that can be taken to mitigate these risks. This should address the risk of not meeting the demand requirement and how any penalties for non-supply will be addressed.

CitiPower/ Powercor will review each non-network option and may seek further information from the non-network provider to better understand the design of the proposed solution and its implications on the network and other network users.

4.1.3 Assessment of non-network proposals

CitiPower/ Powercor will consider the extent to which the non-network solution addresses the network constraint. The proposal must lead to a deferment of a network solution that would otherwise need to be undertaken to address the network constraint at the time of peak demand.

Where the option does not fully meet the constraint, consideration may be given to a hybrid option which combines the non-network solution with a network solution.

The criteria that CitiPower/ Powercor will use to assess each non-network proposal are:

- size, type and location of:

  - load(s) that can be reduced, shifted, substituted or interrupted; or
  - generators that can be utilised if required;
  - the extent to which this addresses the peak demand constraint of the network constraint;

- type of action or technology proposed to reduce peak demand or provide alternate supplies;
- reliability of the proposed solution compared to the network solution;
- time required to implement the proposed solution, and any period of notice required before loads can be interrupted or generators started and whether this is appropriate to address the network constraint;
- the length of time that the network augmentation is deferred;
- implications of the life-cycle of the asset including the predictability of the effectiveness of the possible option;
- quantification of material market benefits; and
- quantification of costs to implement, operate and maintain the option, including:
  - any cost savings that would accrue to the owners/ operators of the equipment;
  - costs of any contribution or assistance that CitiPower/ Powercor may be required to make in order to implement the option, such as network support payments;
  - costs of complying with laws, regulations and applicable administrative requirements; and
  - costs and complexity of any network augmentation works.
  - Any costs that would fall on CitiPower/Powercor should the non network option fail to be available when called upon. This could include STPIS penalties.

In addition, CitiPower/ Powercor may take into account any other information that is relevant to assisting in the investigation and evaluation of non-network options. This will include the possible implications of the non-network solution on other network users.

4.1.4 Ranking of options

CitiPower/ Powercor will prepare a list which identifies all credible options to address the identified need, which includes network solutions. Except where the options are to address a reliability issue, market benefits and costs of each option will be quantified. The credible option with the highest net economic benefit will receive the highest ranking.

Sensitivity analysis may also be undertaken for key input variables to assess whether that is likely to change the ranking of credible options.

Take for example the scenario shown in the table below where there are five credible options to address a network constraint.

Table 4.1: Calculating expected net economic benefit ($m)

Credible option	Market benefits	Costs	Net economic benefit	Ranking
Network option 1	11.3	11.9	-0.6	5
Network option 2	18.0	17.0	1.0	3
Embedded generation option	13.5	12.4	1.1	2
Demand-side option	0.9	0.5	0.4	4
Demand-side option, combined with a network option	14.0	12.0	2.0	1

Source: example taken from AER, *Application guidelines Regulatory investment test for distribution*, 14 December 2018, p. 53.

CitiPower/ Powercor will identify the credible option with the highest net economic benefit as the preferred option. In the above example, this would be the demand-side option combined with a network option.

4.1.5 Draft Project Assessment Report

If CitiPower or Powercor consider that a non-network option forms a credible option or a significant part of a credible option, then it must publish a Draft Project Assessment Report (**DPAR**) within 12 months of the end of the consultation period for the Non-network Options Report.

Clause 5.17.4(j) of the NER sets out the required contents of the DPAR. CitiPower/ Powercor will assess the submissions from the non-network options report as well as its own updated analysis to determine the appropriateness of the solution. The DPAR will provide the outcome of that analysis, and will contain a range of information, including but not limited to:

- a description of the identified need for the investment;
- the assumptions used in identifying the identified need;
- a summary of, and commentary on, the submissions on the non-network options report;

- a description of each credible option assessed;
- a quantification of the market benefits and costs for each credible option, where appropriate;
- a detailed description of the methodologies used in quantifying each class of cost and market benefit;
- Where relevant, the reasons why the RIT–D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option.
- the results of a Net Present Value (**NPV**) analysis of each credible option and an explanatory statement regarding the results; and
- identification of the preferred option, together with:
    - Technical characteristics. Where relevant, this should include its estimated construction timetable, estimated commissioning date, and indicative capital and operating costs.
    - A statement and accompanying analysis that the proposed preferred option satisfies the RIT–D.
    - If the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent.
- Contact details for a suitably qualified staff member of the RIT–D proponent that can receive queries on the draft report.

CitiPower/ Powercor will consult with stakeholders on the DPAR for a period of no less than six weeks.

CitiPower/ Powercor will not publish a DPAR where it has previously determined that no non-network solutions provide a credible option and published a notice under 5.17.4(d) of the NER, and where the estimated capital cost of the preferred option is less than $11 million.

4.1.6 Final Project Assessment Report

As soon as practicable after the consultation period for the DPAR, CitiPower/ Powercor must publish a Final Project Assessment Report (**FPAR**).

Where the submissions to the DPAR report indicate that the analysis of CitiPower/ Powercor in reaching the preferred option may contain omissions or inaccuracies, then it will reassess the options using the processes discussed above in section 4.1.3 and 4.1.4.

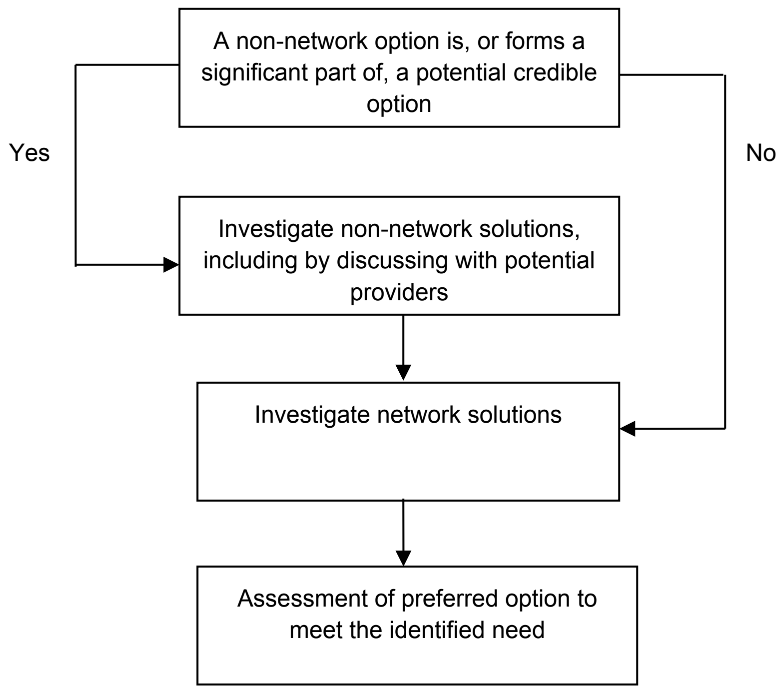
The FPAR must set out a summary of submissions to the draft report, as well as the requirements of clause 5.17.4(j) of the NER.

If the preferred option has an estimated capital cost to CitiPower or Powercor of less than $22 million, then the FPAR may be included as part of the Distribution Annual Planning Report (**DAPR**).

4.2 Streamlined process

Where the estimated capital cost of the most expensive potential credible to address the constraint is likely to be less than $6 million, or the project meets the exceptions to the RIT-D, then the streamlined process will be adopted. This is shown in the diagram below.

Figure 4.2: Streamlined process



The streamlined process consists of the following steps:

- screening process for non-network options;
- investigation into network and non-network options; and
- assessment of preferred option to meet identified need.

Each of these steps is discussed below.

4.2.1 Screening process for non-network options

CitiPower/ Powercor will consider demand management options where it is considered that a non-network solution may provide an efficient and prudent solution or where there may be benefits to obtaining a better understanding of a project as a result of its innovative nature or new technology and how it may apply to future projects.

The screening process, which is similar to that set out in section 0, will include:

- network solutions, such as adding a new transformer and/or building new power lines; and
- non-network solutions, including those referenced in section 3.2.

An initial assessment of the appropriateness of each possible option will be conducted. In some cases, CitiPower/ Powercor may discuss a possible non-network option with one or more participants from its demand-side engagement register. This may assist in scoping out the appropriateness of the option and possible solution.

Alternatively, non-network solution providers can approach CitiPower/ Powercor to discuss possible solutions for identified network constraints. Information on future network constraints is included in the DAPR, which is published by 31 December each year.

4.2.2 Investigation into options to address network constraint

Following the initial screening for options, CitiPower/ Powercor will undertake detailed investigation into possible network and non-network solutions to address the network constraint.

For each network and non-network option, the criteria that will be considered include:

- size, type and location of proposed solution;
- time required to implement the proposed solution and whether or not this meets the identified need;
- implications of the life-cycle of the asset including the predictability of the effectiveness of the possible option;
- approximate total cost to implement the option including connection costs; and
- value, timing and duration of the deferment of capital expenditure that would otherwise be undertaken to address the network constraint at the time of peak demand.

CitiPower/ Powercor may take into account any other information that is relevant to assisting in the investigation and evaluation of the options. This will include the possible implications of the solution on other network users.

4.2.3 Assessment of preferred option to meet identified need

CitiPower/ Powercor will prepare a list which identifies all credible options to address the identified need. The options will be summarised, analysed and then ranked, taking into account:

- estimated cost (both NPV and $/kVA);
- size (MVA);
- time of day and seasonality factors;
- timeframe for delivery; and
- reliability and/or risk.

Generally, the options will be ranked primarily on cost effectiveness, once a reasonable level of confidence in a proposal has been established.

Sensitivity analysis may also be undertaken for each variable to demonstrate how the NPV of the option compares with other options. The option that in the majority of cases is the favoured option will be ranked ahead of the other options. The process will identify the impact of each solution and its cost and incremental cost per kVA and then rank them in order of total cost.

If a non-network solution is considered to be a credible option, either in whole or as part of the overall solution to the network constraint, then CitiPower/ Powercor will commence discussions with the non-network provider. These discussions will cover network support payments, which are further discussed in section 5.

If a non-network solution is not considered to be the preferred option, then CitiPower or Powercor will inform the non-network provider of the outcome of the assessment process. CitiPower/ Powercor will provide reasons to the non-network provider as to why the proposed solution was not the preferred option.

4.3 Worked examples

This section provides high level examples of the process that CitiPower/ Powercor will follow to assess non-network options. It is intended to familiarise stakeholders with the process.

Worked example 1: A planning engineer at Powercor identifies that a particular Zone Substation has a future constraint, with peak demand increasing at an average rate of 1MW per year which is forecast to exceed its capacity in 2018.

The capital cost to Powercor to address this network constraint with a network solution is estimated at $10 million.

The planning engineer considers a range of non-network options and is assisted by discussions with some providers on the demand-side engagement register. The engineer determines that non-network options may be able to individually or jointly address the network constraint. Powercor prepares a Non-network Options Report and publishes it on its website. At the same time, interested parties on the demand-side engagement register are notified.

Stakeholders are given three months to prepare responses to the paper. Responses are received from several providers including ACME Generator Solutions. ACME includes a detailed non-network proposal for a possible solution involving portable gas fired generator sets that can be incrementally added during the contract period.

The ACME proposal is found to satisfy the technical requirements of the solution. The planning engineer holds discussions with ACME to identify reliability, connection augmentations and connection issues. Payments such as Network Use of Service, network support and avoided Transmission Use of System (**TUoS**) are identified, and ACME agrees to indemnity payments under the Service Target Performance Incentive Scheme.

For each network and non-network option, Powercor estimates the market benefits of the option taking into account different scenarios for growth in peak demand. The construction, operating and maintenance costs of each option are also calculated. Powercor ranks the expected net economic benefit of each credible option. The highest ranked credible option is the ACME non-network solution.

Powercor publishes a DPAR which identifies the preferred option and provides a detailed description of the analysis and methodologies used. Stakeholders are given six weeks to provide comments on the DPAR.

Powercor reviews the submissions to the DPAR, but the non-network solution remains the preferred option. Negotiations with ACME are finalised. Powercor includes the FPAR as part of its DAPR, and at the same time notifies parties on its demand side engagement register.

Worked example No. 2: An area planning specialist at CitiPower identifies that a 40km long sub transmission line has a future constraint. Peak demand is increasing at an average rate of 0.5MW per year and this is forecast to exceed the capacity of the line in the summer of 2018/19.

The capital cost to CitiPower to upgrade the conductors to address the network constraint is estimated at $7 million.

The planning specialist considers a range of non-network options and is assisted by discussions with some providers listed on the demand-side engagement register. CitiPower determines that some non-network options may be able to individually or jointly address the network constraint, be both technically and commercially feasible and be able to be implemented in sufficient time.

CitiPower prepares a Non-network Options Report and publishes it on the CitiPower website. At the same time, all interested parties on the demand-side engagement register are notified.

Stakeholders are given three months to prepare responses to the Non-network Options Report. Some stakeholders provide non-network proposals which discuss how their proposed solution would address the future network constraint, including a technical description and other required information. This includes proposals from:

- a demand management aggregator;
- a diesel generator company; and
- a solar energy provider proposing a solution combining a solar energy with battery storage.

CitiPower estimates the market benefits and costs of each option, taking into account different scenarios for growth in peak demand. The expected net economic benefit of each credible option is calculated, and the highest ranked option is the network solution.

CitiPower publishes a notice under clause 5.17.4(d) of the NER setting out the reasons for making the determination, which includes the methodologies and assumptions used in making the decision.

CitiPower includes the FPAR as part of the DAPR, and at the same time notifies parties on the demand side engagement register.

5 Payment flows between parties

Where a non-network solution has been identified as a possible credible option, either:

- in the RIT-D process, following the consultation on the Non-network Options Report and in preparing the Draft Project Assessment Report; or

- in the streamlined process, in the detailed investigation into possible network and non-network options;

then CitiPower/ Powercor will need to discuss payments and contractual arrangements with the non-network provider in accordance with internal processes and procedures.

5.1 Payment principles

CitiPower/ Powercor will apply the following principles in approaching discussions with embedded non-network providers relating to payments:

- negotiation in good faith;

- limiting the exposure of CitiPower/ Powercor and its customers to potential costs arising from failure of the non-network solution to deliver the stated solution; and

- appropriate sharing of risks from any failure of the non-network solution.

5.2 Payments made by the non-network provider

There are two main categories of payments that flow from the non-network provider to CitiPower/ Powercor:

- Network Use of Service payments (**NUoS**); and

- indemnity payments for failure to provide a service.

5.2.1 Network use of service

NUoS is a payment that is passed through to the customer which is intended to recover the costs of the shared network, as required under the national or jurisdictional requirements.

5.2.2 Indemnity for failure to provide a service

The amount of compensation to be provided by the non-network provider to CitiPower/ Powercor for failing to provide network support services must relate to:

- the costs incurred by CitiPower/ Powercor;

- the impact on the applicable service adjustment; and
- any immunities to which CitiPower/ Powercor may be entitled.

This will include incentives and penalties for CitiPower/ Powercor to drive reliability improvements under the Service Target Performance Incentive Scheme (**STPIS**).

STPIS risk will be transferred to the non-network solution provider as part of the contractual arrangement to address degradation of reliability caused by the non-network solution.

5.3 Payments made by CitiPower and Powercor

There are three main categories of payments that flow from CitiPower/ Powercor to the non-network provider:

- Network support payments;
- Avoided Transmission Use of System (**Avoided TUoS**) payments; and
- Funding for non-network solutions may also be available through applicable incentive schemes, such as the AER's Demand Management Innovation Allowance and Demand Management Incentive Scheme.

5.3.1 Network support payments

Network support payments arise where an embedded generator has the potential to reduce the long term need for investment in the transmission and distribution networks.

5.3.2 Avoided TUoS

By using an embedded generator a situation can arise where CitiPower/ Powercor may offset some of the maximum demand at a particular location. This is because embedded generators are connected directly into the distribution network. As such, CitiPower/ Powercor avoid the future augmentation of the transmission system, and hence avoid the associated locational component of the TUoS charge.

As required under clause 5.5(h) of the NER, the calculation of the avoided TUoS reflects the value of the peak demand at the transmission connection point which has been avoided by the use of the embedded generation. The avoided TUoS benefit can be included in the non-network proposal business case. The calculations are shown in Appendix A.

5.3.3 Demand Management Innovation Allowance (DMIA) and Demand Management Incentive Scheme (DMIS)

The DMIA provides a limited regulatory allowance for Powercor and CitiPower 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 funding.
For the 2016-2020 regulatory control period, Powercor has been allocated $3M over 5 years and CitiPower $1m.

As well as the DMIA the AER has designed a new DMIS (Demand Management Incentive Scheme) to provide higher incentives for distributors to adopt more demand management measures.

The details of the new DMIA are available on the AER's website:
https://www.aer.gov.au/system/files/AER%20-%20Demand%20management%20incentive%20scheme%20-%2014%20December%202017.pdf

6 Connecting embedded generators

This chapter sets out the process for lodging an application to connect an embedded generator. It also discusses the principles for the setting of charges, terms and conditions of those connections.

The NER set out two sets of provisions relating to connecting embedded generators:

- chapter 5.3A applies to connecting of generators or large embedded generators for a registered or intending market participant, which exceeds the exemption limit (currently 5MW) for registration as a participant with AEMO; and
- chapter 5A applies to connecting non-registered or micro-embedded generators.

These processes are discussed in turn below.

6.1 Connections under chapter 5.3A of NER

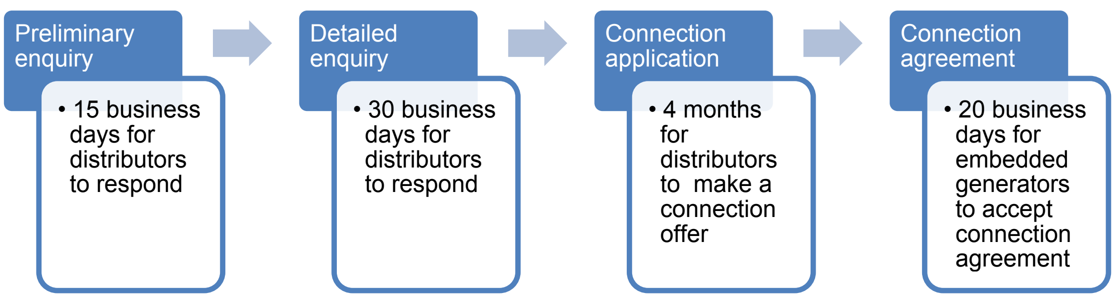
The process in chapter 5.3A of the NER applies to embedded generators that are registered with AEMO, intending to register with AEMO, or required to seek exemption from registration as a generator with AEMO.

The NER contains detailed requirements in terms of process, timeframes and information provision. The connection process involves:

- enquiry process: a two stage process consisting of a preliminary enquiry stage followed by a detailed enquiry stage; and
- application process: following the enquiry stages, an embedded generator proponent may lodge an application to connect with a distributor, and the distributor will provide a connection offer.

The process is shown in the diagram below.

Figure 6.1 Connection process for embedded generators under chapter 5.3 of NER



Note: timeframes can be extended by agreement of the parties

Excluding the time taken by embedded generator proponents to provide information, the chapter 5.3 process may take approximately 25 weeks.

Charges, terms and conditions for connections under chapter 5.3 of the NER

Connection charges are to be negotiated in good faith between the distributor and proponent. The connection offer must:

- contain an itemised statement of connection costs in any connection offer;
- be fair and reasonable;
- entitles the distributor and the connection applicant to negotiate, which must be conducted in good faith; and
- contain the terms and conditions of the kind set out in schedule 5.6 of the NER.

An offer to connect must define the basis for determining the distribution service charges in accordance with chapter 6 of the NER, including the prudential requirements in part K of chapter 6.

An offer to an embedded generator must conform with the access arrangements set out in rule 5.5 of the NER. This includes additional requirements in terms of the connection offer, including:

- reaching agreement on the compensation to be provided by the distributor to the embedded generator, or vice versa, in the event that they are constrained on or off during a trading interval;
- the maximum negotiated use of system charges applied by the distributor must be in accordance with the applicable requirements of chapter 6 of the NER and the negotiated distribution service criteria applicable to the distributor; and
- a distributor must pass through the locational component of prescribed TUOS charges that would have been payable by the distributor to a transmission company had the connection applicant not connected to the network.

Further details regarding the factors that CitiPower/Powercor takes into account when assessing an application, or in negotiating a connection agreement, such as the technical requirements, are found in the connection guidelines relating to:

- low voltage lines;
- high voltage lines; and
- sub-transmission lines.

These guidelines are available from the CitiPower/Powercor websites.[1]

6.2 Connections under chapter 5A of NER

The Chapter 5A connection process is more flexible and shorter than chapter 5. It applies to non-registered embedded generators and micro-embedded generators. Non-registered generators may elect to use the connection process under chapter 5 of the NER.

CitiPower/Powercor offer two types of connection services to embedded generators under chapter 5A of the NER:

- basic connection service: for micro-embedded generators that comply with Australian Standard (**AS**) 4777; or

- negotiated connection services: for micro-embedded generation requiring greater than 5kW per single phase connection and greater than 30kW for a three phase connection; or any embedded generation that is not micro-embedded generation (i.e. not compliant with AS4777);

These are discussed below.

6.2.1 Basic connection services

Basic connection services include the connection of small scale renewable energy micro-generation systems (i.e. micro-embedded generators) to the network via an inverter, and do not require network augmentation.

The inverter must have a capacity of no more than 5kW single phase, or no more than 30kW for a three phase connection, and the customer must have sought and received pre-approval from us for the requested capacity of the generator. A pre-approval application can be made through the eConnect portal. Once the pre-approval is provided, the installer or Registered Electrical Contractor (**REC**) can complete the installation of the embedded generator and submit the embedded generation connection application through the eConnect portal.

Pre-approval of export capacity is required prior to connection of a basic connection service. Further information on the pre-approval process is available from the CitiPower/Powercor website.[2]

Charges, terms and conditions for a basic connection service

CitiPower/ Powercor have published model standing offers (**MSO**) for the provision of basic connection services. The MSO contains the terms and conditions for the basic

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1 Refer https://www.powercor.com.au/our-services/electricity-connections/solar-and-other-generation/connecting-larger-embedded-generator-systems/

2 Refer https://www.powercor.com.au/our-services/electricity-connections/solar-and-other-generation/

connection service with micro-embedded generation. The MSO is available from the website.

If a customer rejects our model standing offer for basic connection service, or wishes to negotiate the terms and conditions of an offer, then the customer may seek a negotiated connection offer. A connection application fee may apply for negotiated offers.

A fixed fee is charged for a basic connection services.

In addition, where a customer is seeking the connection of embedded generation, a charge for reconfiguration of the electricity meter (where we are the meter provider) may be levied.

The relevant fees will be the AER approved tariffs for the calendar year, contained within our published General Service Charge Pricing Schedule.[3]

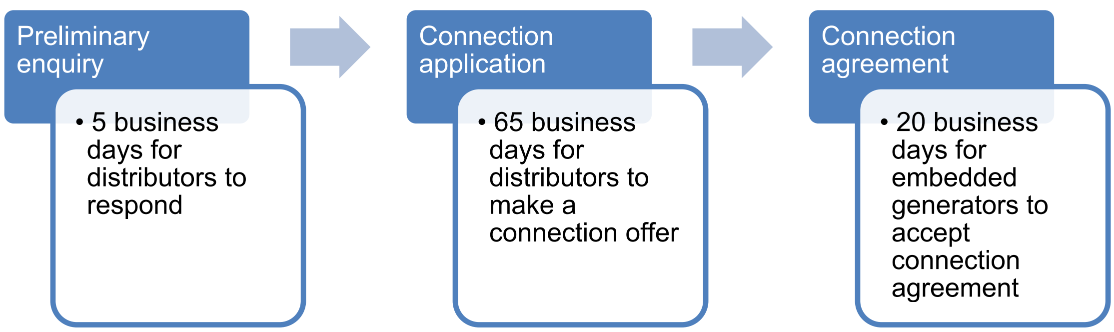
6.2.2 Negotiated connection services

Negotiated connection services are those that do not meet the criteria for a basic connection service. That is, the connection may be too large or complex, or require network augmentation. This may include micro-embedded generation requiring greater than 5kW per single phase connection and greater than 30kW for a three phase connection.

For generation between 30kW and 200kW, then a detailed assessment of the connection needs to be undertaken. This requires lodgement of a written application form by the applicant. Once the application is received, CitiPower/Powercor will contact the connection applicant to assist with the approval and connection processes.

The process for a negotiated connection offer is shown in the figure below.

Figure 6.2 Negotiated connection process under chapter 5A of NER



[3] Available from: https://www.powercor.com.au/about-us/electricity-networks/network-tariffs-and-charges/

A negotiated connection service offer will be provided to the customer within 65 business days of the date of the completed application being received (not counting any time in which further information that we have sought from the customer is provided). The offer will remain valid for 20 business days.

Charges, terms and conditions for negotiated connection services

Customers may seek to negotiate a connection offer, or seek an offer where the connection service does not meet the criteria for a basic connection service.

The factors that CitiPower/Powercor takes into account when assessing an application, or in negotiating a connection agreement, such as the technical requirements, are found in the connection guidelines relating to:

- low voltage lines; and
- high voltage lines.

These guidelines are available from the CitiPower/Powercor websites.[4] In addition, a template connection contract for negotiated connection services is available from the websites.[5]

The connection charges associated with negotiated connection offers will vary, depending on customer type and the specific requirements of the connection service.

An upfront fee may also be levied on customers seeking a negotiated connection offer. The fees will be calculated using our AER approved network tariffs and charges.

A connection charge will be calculated according to the following formula:

$$Connection\ charge = AS + CC + PS$$

where:

AS is the total charge payable for all applicable ancillary services

CC is the total capital contribution payable for all standard control connection services, which are calculated with reference to the cost-revenue-test

PS is the total charge payable to account for any pioneer scheme applying to the assets to which the customer connects

To determine the connection charge, CitiPower/Powercor will calculate the charge for each component based on the least cost technically acceptable standard necessary for the connection.

[4] Refer https://www.powercor.com.au/our-services/electricity-connections/solar-and-other-generation/connecting-larger-embedded-generator-systems/

[5] Refer https://www.powercor.com.au/our-services/electricity-connections/upgrade-or-extend-electricity-supply/#Neg

Where a connection applicant requests a higher standard, which may include an applicant requesting a point of supply to the property requiring additional extension works or a request for a reserve high voltage feeder, the connection applicant shall pay the additional cost of providing the service to the standard requested.

Certain connection applicants may also be required, or in some cases may request, to make a pre-payment to initiate design or purchasing of long lead time material. Full payment of connection charges is generally required before construction commences.

Further details of the calculation of connection charges are set out in the connection policy, available from the CitiPower/Powercor website.

7 Further information

This chapter sets out further sources of information for interested non-network providers.

7.1 Further information

Table 7.1 Links for further information

Topic	CitiPower	Powercor
Distribution Annual Planning Report Transmission Connection Planning Report:	https://media.powercor.com.au/wp-content/uploads/2019/02/05081603/CitiPower-Distribution-Annual-Planning-Report-2018-final.pdf	https://media.powercor.com.au/wp-content/uploads/2019/02/05081809/Powercor-Distribution-Annual-Planning-Report-2018-final.pdf
RIT-D	RIT-D and application guidelines are available from the AER website at: https://www.aer.gov.au/system/files/AER%20-%20Final%20RIT-D%20application%20guidelines%20-%2014%20December%202018_0.pdf	
Demand management	https://media.powercor.com.au/wp-content/uploads/2018/11/26090401/demand-side-engagement-strategy-v20_final.pdf	https://media.powercor.com.au/wp-content/uploads/2018/11/26090401/demand-side-engagement-strategy-v20_final.pdf
Connection for embedded generators	https://www.powercor.com.au/customers/electricity-connections/solar-and-other-generation/	https://www.powercor.com.au/customers/electricity-connections/solar-and-other-generation/

7.2 Contact details

Should you have any queries or require further information relating to the contents of this report, please contact:

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- CitiPower Customer Service
  - General Enquiries: 1300 301 101
  - Website www.citipower.com.au
  - Email info@powercor.com.au
- Powercor Customer Service
  - General Enquiries: 13 22 06
  - Website www.powercor.com.au
  - Email info@powercor.com.au

Appendix A Avoided TUoS

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

A.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.

A.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.

A.3 Avoided TUoS calculations for a single generator

The following process outlines the method that CitiPower/ Powercor will use 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 clause 3.5.[6]

[6] AEMO, *Approved amended pricing methodology for prescribed shared transmission services for*

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.

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

c) Calculate the Avoided Demand (AvoidedTUOS)

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}.

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

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.