Demand Side Engagement Document

Version 2

31st August 2016

SA Power Networks
www.sapowernetworks.com.au

Disclaimer

This document describes policies and procedures used by SA Power Networks to engage with parties who wish to connect generation assets to our network or respond with proposals to resolve constraints on our network.

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Document Version history & effective date

Version	Issue Date	Notes
1.0	30-8-2013	Initial Publication
2.0	30-8-2016	Revised version including: • Removal of material duplicated within the DAPR; • Reordered and updated sections to reflect current practises (2016) • Updated website references (June 2016)

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Glossary of terms

Term	Meaning
AEMC	Australian Energy Market Commission.
AEMO	Australian Energy Market Operator.
AER	Australian Energy Regulator.
AS4777	Australian Standard for grid connection of energy systems via inverters.
DAC	Development Assessment Commission.
DAPR	Distribution Annual Planning Report. A report published by SA Power Networks describing our network, forecasting future loads and describing any emerging constraints.
DPAR	Draft Project Assessment Report. A report published in accordance with clauses 5.17.4 (i) – (n) of the NER.
DNSP	Distribution Network Service Provider. An entity who engages in the activity of owning, controlling or operating an electricity distribution system. The DNSP for South Australia is SA Power Networks.
EDC	Electricity Distribution Code. The rules governing the distribution of electricity in South Australia.
ESCOSA	Essential Services Commission of South Australia.
ETC	Electricity Transmission Code.
FPAR	Final Project Assessment Report.
GSL	Guaranteed Service Level. A payment made by SA Power Networks to a customer when we fail to meet certain levels of service guaranteed under our license conditions.
HV	High Voltage. A voltage greater than 1 kV.
Identified Need	means the objective a Network Service Provider seeks to achieve by investing in the network.
LRET	Large scale Renewable Energy Target.
LV	Low Voltage. A voltage less than or equal to 1 kV.
N-1	When used in the sense of System Reliability this means that all equipment in the network is in service (N) with the exception of a single piece of equipment (-1).
NCA	Network Connection Agreement. An agreement between us and a party connecting to our network that describes both parties' obligations and rights.

Term	Meaning
NEM	National Electricity Market.
NER	National Electricity Rules. Copies of the NER can be obtained from the AEMC website: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.
NNOR	Non-Network Options Report. A report requesting proposals for network services or support from third parties in response to an identified need.
NSSA	Network System Support Agreement. An agreement in which a party external to us agrees to provide network support services as a non-network alternative to a network augmentation.
OTR	Office of the Technical Regulator. The body in South Australia responsible for monitoring compliance with the Electricity Act, including technical and safety standards.
SAIDI	System Average Interruption Duration Index. This is a measure of the average number of minutes each customer is without supply in a given year.
SAIFI	System Average Interruption Frequency Index. This is a measure of the average number of interruptions each customer experiences in a given year.
STN	Screening Test Notice. The notice published under clause 5.17.4 (d) of the NER that explains why no Non Network Options Report will be published.
STPIS	Service Target Performance Incentive Scheme. A scheme that provides financial incentives to maintain or improve network reliability developed and published by the AER in accordance with clause 6.6.2 of the NER.
System Limitation or System Constraint	A forecast limitation on the ability to supply electricity identified by a Distribution Network Service Provider under clause 5.13.1(d)(2) of the NER.
TNSP	Transmission Network Service Provider. A person who engages in the activity of owning, controlling or operating a transmission system. The TNSP for South Australia is ElectraNet.
TUOS	Transmission Use Of System. A charge paid to the TNSP to cover the cost of the transmission system.
VCR	Value of Customer Reliability. The value that electricity customers place on avoiding service interruptions. The VCR determines how much customers are willing to pay for improved service.

1 Introduction

1.1 Purpose of document

This document is intended to inform external parties of SA Power Networks strategy for:

- enabling the connection of embedded generators to our network;
- engaging with non-network solution providers;
- considering the use of non-network solutions to resolve an identified need.

It satisfies the requirements of clauses 5.13.1 (g) - (h) of the National Electricity Rules (NER) and contains the information specified in schedule 5.9 of the NER.

1.2 Other References

Further information may be found on SA Power Networks website at www.sapowernetworks.com.au.

Additional information on the rules and regulations controlling the electricity network in South Australia and the connection of assets to that network is available on the websites of the following organisations:

AER: www.aer.gov.au

AEMC: www.aemc.gov.au

AEMO: www.aemo.com.au

OTR: www.sa.gov.au/directories/government/other-state-bodies/office-of-the-technical-regulator

ESCOSA: www.escosa.sa.gov.au

ElectraNet: www.electranet.com.au

1.3 Contacts for further information

We welcome any comments or queries you may have in relation to the contents of this document. Enquiries regarding this document should be emailed to:

requestsforproposals@sapowernetworks.com.au

Alternatively, written submissions may be addressed to:

SA Power Networks
Attention: Manager Network Planning
GPO Box 77,
Adelaide, SA, 5001

2 Demand Side Engagement Register (DSER)

SA Power Networks encourages any party that has an interest in the long term planning, operation and development of the electricity distribution network in South Australia to register their interest with SA Power Networks via the Demand Side Engagement Register. Those who register on the DSER, will be notified when SA Power Networks publishes any document required under chapter 5 of the NER including:

- The Distribution Annual Planning Report (DAPR);
- The Demand Side Engagement Document (DSED);
- Publications associated with the performance of the Regulatory Investment Test – Distribution (RIT-D) such as Screening Tests or Non Network Options Reports.

Registration is NOT a precondition of either viewing or responding to any of the above documents.

In order to be added to the DSER, it is a simple process of completing an online form located on SA Power Networks website providing your name and email address. SA Power Networks will use this email address solely to advise you when we publish documents associated with chapter 5 of the NER on our website.

Note that this information is not used by SA Power Networks for any other purpose including identification of possible equipment suppliers or service providers.

The relevant form may be found on SA Power Networks' website at:

http://www.sapowernetworks.com.au/engagementreg/index.jsp

More information on SA Power Networks' Privacy Policy can be found at:

http://www.sapowernetworks.com.au/centric/home/privacy_policy.jsp

3 Embedded generation connection process

3.1 Summary

Embedded generation is the term given to generation equipment that is connected to a DNSP's network including:

- Residential and Commercial inverter based generation; eg Photo Voltaic (PV) Panels;
- Energy storage systems capable of exporting electricity into the network;
- Generators which run in parallel (that is are connected) to the DNSP's network through the customer's switchboard irrespective of whether or not they export energy back to the electricity grid;

Such generation does not include any generation or electricity storage system that is not connected to the electricity grid such as:

- Standalone PV powered pumps;
- Off-grid residential PV or wind powered systems;
- Portable diesel or petrol generator sets.

Under the NER, a customer **must** apply to SA Power Networks prior to connecting a generator to our network, even if its only purpose is to provide a backup supply when power is unavailable.

3.2 Small Embedded Generators (SEG)

These are inverter connected systems with a maximum total capacity at the point of supply of 5kVA on SWER systems, 10kVA single phase or 30kVA three phase. Customers should refer to the Small Embedded Generation Technical Guidelines, available from SA Power Networks website at:

http://www.sapowernetworks.com.au/public/download.jsp?id=23869

Comprehensive information regarding the connection of small embedded generation (SEG) to our network including connection forms, technical guides and advice on how to plan an installation can be found on the SA Power Networks website at:

http://www.sapowernetworks.com.au/centric/customers/embedded_generation.jsp

3.3 Large Embedded Generators (LEG)

Requests to connect embedded generation to our network other than those classed as small embedded generators (that is other than inverter based systems < 30kW) are dealt with differently. The connection process and requirements for these are described in NICC 270: Guide for Connection of Large Embedded Generation; available from SA Power Networks website at:

http://www.sapowernetworks.com.au/public/download.jsp?id=47673

Designers, contractors and consultants should also read the following documents. They provide a detailed description of the technical connection requirements depending on the size and type of generation equipment proposed to be connected, and are available from SA Power Networks website:

(i) TS 130 - Technical Standard for Large Inverter Generating Systems 200kW or less;
http://www.sapowernetworks.com.au/public/download.jsp?id=47669

(ii) TS 131 - Technical Standard for Large Inverter Generating Systems above 200kW or Rotating Generating Systems.
http://www.sapowernetworks.com.au/public/download.jsp?id=47670

For these types of systems, we charge a fee that covers our costs of enabling the connection – for instance to cover the cost of assessing the impact of the proposal on our network. Fees will be incurred even if the connection does not proceed. These fees are explained in the NICC 270: Guide for Connection of Large Embedded Generation document, which can be found from the SA Power Networks website at:

http://www.sapowernetworks.com.au/centric/customers/embedded_generation.jsp

4 Network Planning Process

4.1 Overview

SA Power Networks follows an annual planning process to identify and respond to changes in forecast demand. Each step in this cycle and details of the planning criteria used to identify network constraints is explained in detail in the Distribution Annual Planning Report (DAPR). This report is published annually prior to 31 December in accordance with the requirements of clause 5.13.2 and schedule 5.8 of the NER and is available from SA Power Networks website at:

http://www.sapowernetworks.com.au/dapr/index.jsp

We welcome comments on the contents of the DAPR. It is important to note that:

- For projects < $5 million[1], the identification of the project in the DAPR is the only opportunity for third parties such as suppliers of non-network solutions to propose alternative solutions to those that we have identified.
- Constraints and any associated potential solution will often be identified within the DAPR prior to the publication of any documents associated with the initiation of the RIT-D for the identified need. The DAPR will also include information about the likely key dates for the RIT-D process (eg when it is likely to be published).

In overview, the process used to identify and resolve network constraints consists of:

- Forecast load at key points in our network for at least the next 5 years.
- Compare the forecast demand to the relevant capacity of the network to identify any forecast network constraints. These constraints are referred to as "identified needs" within the NER. These two terms are used interchangeably within this document.
- Identify the optimal method of resolving these identified needs taking into consideration the cost, timing and the technical capability of the options explored. Where required, SA Power Networks will consult with third parties seeking alternative proposals to resolve the identified need through the RIT-D process (refer Section 5).
- Program the proposed solution into our future construction timetable and capital budgets.
- Undertake the proposed works. For significant projects such as the construction of a new zone substation, there may be several years between initial identification of the need and implementation of the preferred solution.

Figure 1 illustrating the planning process can be found on page12.

4.2 Identifying Solutions

Once a network constraint is identified, SA Power Networks explores a range of possible options to defer or resolve the constraint. These options may be some combination of either:

1. Changes or additions to the existing network, typically performed by us (that is a network solution); or
2. Support of the existing network often proposed or executed by others (that is a non-network or demand management solution)

We plan our network based on a "whole of area" basis. That is, we will seek to find the solution which best resolves as many constraints as possible rather than seeking individual solutions for each identified constraint.

[1] The threshold amount at the time of publication (2016) is $5 million for all DNSP projects. Note that this value is reviewed every three years; for the current value please refer to the AER's website.

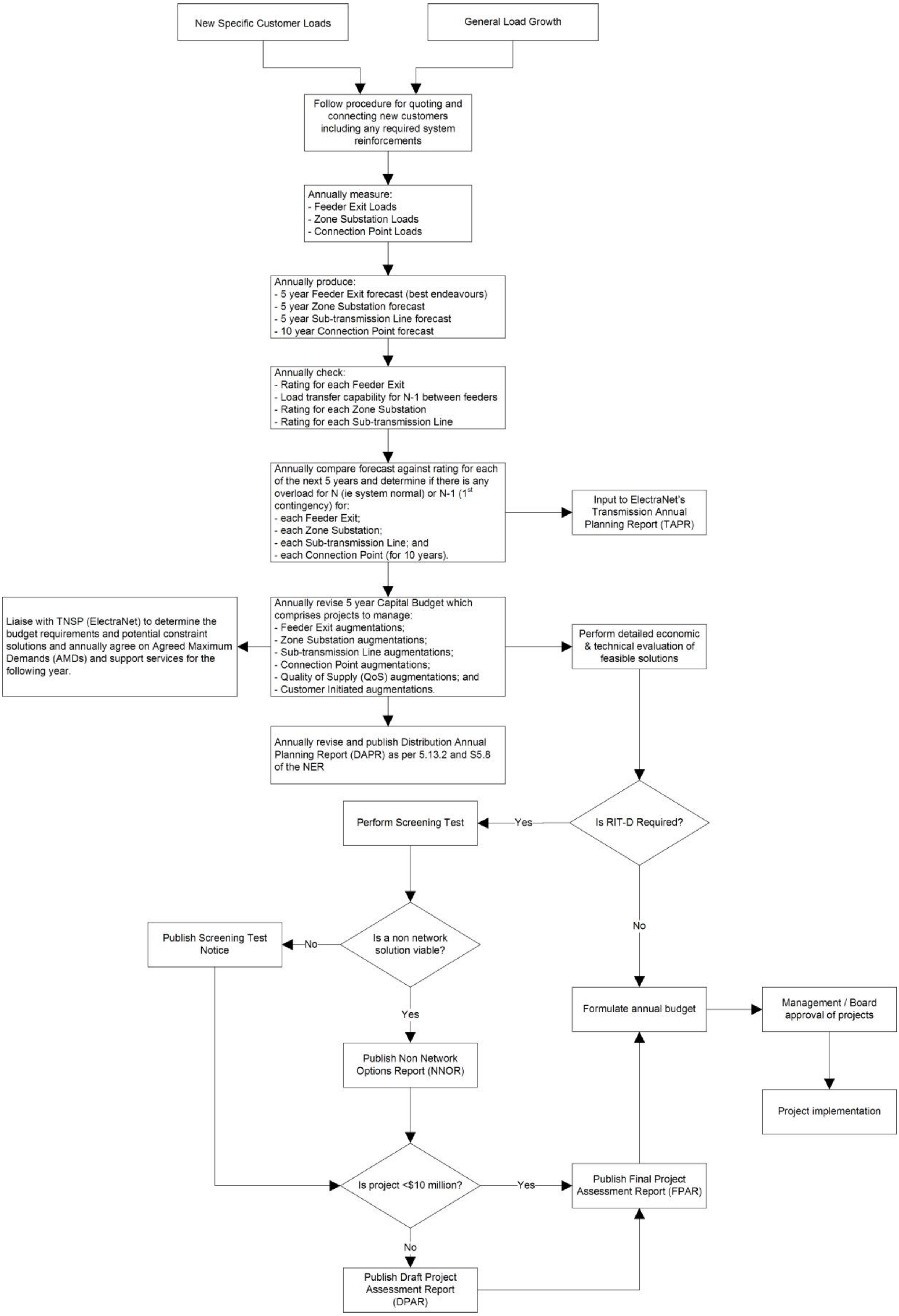

Figure 1 Network Planning Process

We will in all cases implement the technically viable solution with the lowest overall cost - highest benefit (such as increasing available load transfers or improving power factor) prior to any consideration of more expensive solutions such as building new substations or sub-transmission lines.

We recognise that alternatives to network solutions may exist, which may deliver either a lower cost solution or provide greater benefits to the electricity market as a whole (including electricity consumers). The methods by which non-network solutions may achieve this include:

- the use of embedded generation / storage to reduce peak demand on the network;
- shifting consumption to a period outside the peak period;
- increasing customer's energy efficiency; or
- curtailing demand at peak periods, with the agreement of the relevant customer(s).

The assessment of the possible options is formally performed through the RIT-D process for large qualifying projects and through a similar but simplified cost benefit analysis for small projects.

4.3 Project Options Evaluation

For all projects we evaluate all identified options, both network and non-network, to identify our preferred (least cost – maximum benefit) solution. We use criteria that reflect the regulatory requirements under the NER and the RIT-D Guideline published by AER to evaluate all options without prejudice to ownership or technology.

For those identified needs for which the most expensive credible option is more than $5 million[2] a:

- Formal Screening Test is performed to confirm whether potential non-network solutions exist to resolve the identified need at a cost no greater than the most expensive credible network option.
- Screening Test Notice is published where the Screening Test confirms that no non-network solution is competitive.
- Non Network Options Report is published requesting proposals from the market to resolve the identified need for those cases where the Screening Test confirms that a credible non-network solution (in full or part) may exist.
- Final Project Assessment Report (for projects costing less than $10 million) or a Draft Project Assessment Report followed (after the required consultation period and considering public submissions) by the Final Project Assessment Report, once a final solution (network, non-network or combination of both) has been determined.

Note that for a non-network solution to be considered a viable solution, it must demonstrate that it, either alone or in combination with other options (including network options):

1. resolves all of the identified network constraints;
2. is technically viable and uses proven technology with adequate management of risks including environmental (eg sufficient load reduction can be achieved to remove or delay the identified need);
3. is economically viable (ie the combination of costs and benefits is better than the alternative solutions); and
4. is deliverable within the required timeframe to resolve the identified need.

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[2] Please refer to the NER for a full list of conditions under which a RIT-D test is required or for where a RIT-T test is substituted in its place.

4.4 Project Implementation

In many cases, the installation of electricity infrastructure requires formal planning approvals prior to construction commencing; for instance, where a new substation is a non-conforming use under a district plan.

More information on the Development Application Process through which planning approvals are requested can be found on the Department of Planning, Transport and Infrastructure's (DPTI) website at

www.dpti.sa.gov.au

In the case where any required planning approval is either refused or granted subject to conditions such that the costs of the preferred solution substantially change, SA Power Networks will review the alternatives and revisit the RIT-D process to ensure that the proposed solution remains the most appropriate solution.

Note that the timing of projects may change depending on a number of factors such as changes in forecast loads, the timing of external customer projects or customer closures. If the delay in construction becomes substantial, then the project may be re-assessed and (if applicable) the RIT-D re-performed to ensure that the proposed solution remains the preferred option.

5 The Regulatory Investment Test - Distribution

5.1 Introduction

We are required to apply the Regulatory Investment Test – Distribution (RIT-D) in accordance with section 5.17 of the NER and the AER's RIT-D Application Guidelines. Under the NER, the following documents are required to be produced:

- Screening Test Notices;
- Non Network Options Reports;
- Draft Project Assessment Reports; and
- Final Project Assessment Reports.

Details of the prescribed content of these documents and the process to be followed to generate them can be found within the regulatory test guidelines at:

http://www.aer.gov.au

Documents published by SA Power Networks' under the RIT-D process can be found on our website at:

http://www.sapowernetworks.com.au/ritd/index.jsp

5.2 Definition of Reliability Corrective Action

One of the key decisions of the evaluation is whether or not the identified need (that is a system constraint) is for reliability corrective action. SA Power Networks regards the following constraints as meeting the criteria for reliability corrective action and consequently the preferred option does not have to return a positive net economic benefit within the terms of the guideline:

- Voltages outside statutory or contractual bounds for either 'N' or 'N-1' conditions;
- Equipment overloads for 'N' or 'N-1';
- Inability to meet fault clearing times required for system stability;
- Network fault levels exceeding equipment ratings or above standards agreed with SA Power Networks' customers;
- Breaches of power quality standards as specified in schedule 5.1 of the NER, for instance harmonic distortion, flicker or phase imbalance;
- Equipment or situations that present an unacceptable safety risk to the general public, for instance breach of statutory clearances of overhead lines.
- Failure to meet reliability standards as specified in the EDC;
- Power factors at transmission connection points;
- Network connection requests.

As the planned use of involuntary load shedding to remedy the above constraints would be a breach of our licence obligations, we are obligated to remedy the constraint in accordance with the timeframes specified within our planning criteria.

We regard the following identified needs as not falling under the definition of "Reliability Corrective Action" and therefore require a positive net economic benefit to proceed:

- Provision of a second source of supply to radial substations or single transformer substations where no capacity constraint exists;
- Removal of constraints restricting the ability of embedded generators (both large and small scale) to participate in the NEM;

5.3 Project Timelines

SA Power Networks will, where possible, follow the timelines for the project outlined in the DAPR. However, the lead times indicated may change where:

- Load forecasts change and either bring forward or delay the date of the identified need;
- Customer related projects alter the timing and location of an existing identified need or introduce a new one. For example, a request to connect a large customer may bring forward the timing of a constraint.

For capacity projects where the cost is less than the RIT-D threshold and / or involves the upgrading of assets due to unforeseeable demand increases we will advise interested parties of the proposed augmentations to the network via the DAPR. For these projects, this will be the only opportunity for interested parties to propose projects to resolve these identified needs.

It should be remembered that one of the criteria for any third party proposal, is that it can be constructed / implemented prior to the forecast date of the identified constraint. SA Power Networks will reject a proposal which is technically and / or financially viable if the time required to implement the proposed solution exceeds the published required resolution date.

5.4 Evaluation of Costs

5.4.1 Network Capital Costs

Costs are estimated using either firm tender prices (where they exist) or unit costs that reflect SA Power Networks' experience with similar projects in the past and represent the weighted average cost of construction (ie they have an equal chance of being low as being high). These unit costs are the same as used by SA Power Networks in preparing its Reset submission in accordance with Chapter 6 of the NER.

5.4.2 Maintenance and Operating Expenses

We generally apply a fixed percentage of initial costs each year to cover the cost of operating and maintaining network assets. However, where a specific item is expected to have higher maintenance costs, such as ongoing compliance costs for an embedded generator owned by us, we will either add specific costs into the evaluation or escalate the percentage applied to reflect the operating and maintenance costs expected to be incurred by SA Power Networks. Alternatively, where a specific item is expected to have lower maintenance costs due to its nature then we will adjust the percentage accordingly.

Where an option does not require network equipment to be installed, then no operational and maintenance costs are included; for instance, in the case of a third party non-network solution. However, a charge to cover initial and ongoing contract and operational administration may be applicable. These charges will be specifically identified and costed within the evaluation.

5.4.3 Non Network Costs

Payments to third parties for the provision of non-network services are treated as specified by the AER in the guidelines; for instance, network support payments are treated as annual operational expenses and are not capitalised.

5.5 Evaluation of Benefits

Under the NER and the AER's RIT-D Application Guidelines, SA Power Networks when ranking the options as part of its analysis it must include the impact of all market benefits that may make a material difference to the ranking of the options. The Guidelines identify the following potential benefits which are to be considered in the analysis:

- Changes in the reliability of supply as determined by changes in the expected level of involuntary load shedding;
- Changes in voluntary load curtailment;
- Changes in electrical system losses;
- Changes in load transfer capability;
- Changes in costs to other parties;
- Impact on electricity markets.

5.5.1 Reliability

SA Power Networks uses the value of customer reliability (VCR) for South Australia as published by AEMO. Details of the basis for the determination of these values can be found at:

http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning

When calculating the likelihood of an outage, we use standard outage rates for the various asset classes within our network; eg number of outages per km per annum for overhead sub-transmission lines or outages per annum for substation transformers. These rates are then adjusted by the number of hours per annum that an outage puts the network at risk. For instance, if load will only have to be shed for 10 hours per annum following the loss of a transformer at a substation (that is, for a loss at peak times) then the risk is multiplied by $\frac{10}{8{,}670}$ hours to give an annual value of load at risk.

Where local load is supported by embedded generation that cannot run following loss of supply, (eg roof top PV) we include the impact of the loss of this local generation when calculating the load at risk as the VCR is an estimate of the value of electrical services lost, irrespective of where the electricity supplying those services originates.

5.5.2 Changes in Voluntary Load Curtailment

One possible non-network solution to resolve capacity constraints is to pay customers to curtail (ie reduce) their electricity demand at peak times. There may be two components to this payment:

1. Payment per MWh of energy curtailed; and
2. An availability payment to the customer or scheme aggregator to enable load to be shed.

We treat both components in accordance with the published AER guideline.

5.5.3 Electrical Losses

SA Power Networks estimates the annual electrical losses (in MWh) for each option using network models and information recorded by our SCADA system. We then convert these into a financial value by multiplying these losses by the estimated long term weighted average price of generated electricity (per MWh) in the South Australian market.

As losses are generally small relative to the total energy produced, we assume that they do not drive the need for an increase in generation or transmission capacity.

5.5.4 Changes in Load Transfer Capability

This relates to the ability to transfer load:

- permanently between sources of supply to delay network upgrades; or
- temporarily between network sources of supply following failure as a supply restoration measure; or
- following a supply outage to non-network equipment such as backup generators.

In the first case, this is reflected by changes in the timing of network upgrades. In the second and third cases, this is reflected by changes in reliability through a reduction of involuntary load shedding. Consequently, SA Power Networks does not explicitly consider this category in its analysis.

5.5.5 Costs to other Parties

Where an option changes costs to other parties, there may be a benefit (positive or negative) that should be included in the analysis. For this to occur the benefit must arise as a consequence of participation in the NEM (ie be electricity related).

Currently, SA Power Networks is unaware of any benefits that fall into this category that are not already accounted for within other aspects of the analysis. We will continue to assess this on a case by case basis.

5.5.6 Impact on Electricity Markets

For impacts on the electricity market to be material in the ranking of the options under consideration by the RIT-D, either the generation fuel mix must change, or the wholesale cost of electricity must change as a result of one or more of the options.

Given that peak demand within the SA electricity market is greater than 3,000 MW, it is highly unlikely that a change (typically in the order of a few MW) through the use of a non-network solution will trigger the requirement for either new generation or the mothballing of existing generating plant. Consequently, volume impacts on the wholesale market as the result of an option are unlikely.

In addition, nearly all peaking plant in the SA market is diesel fuelled, which is the same fuel that is typically used by small embedded generators to resolve distribution network constraints under a non-network solution. It is therefore unlikely that there will be any fuel substitution impact due to the use of embedded generation solutions considered under the RIT-D.

Where this is not the case, for instance in the case of a large PV plant combined with energy storage, SA Power Networks will consult with the TNSP (ElectraNet) on potential market impacts and include these impacts (if material) in its analysis.

5.6 Exclusions

Under the regulations there are a number of elements that we **must** exclude from consideration when evaluating options. These include costs / benefits which have no financially quantifiable impact on the economic operation of the National Electricity Market. Examples are:

- The aesthetic impact of electricity assets on the landscape; or
- Environmental impacts such as changes in greenhouse gas emissions.

In addition, we **must** also exclude economic transfers between parties participating in the market. This means that we are not allowed to take into account how profits or costs are shared between market participants (both individuals and companies) operating in the NEM. This includes impacts on our own profit. Examples of these excluded elements include:

- Reduction in profits made by generation companies where an option increases competition;
- Incentive payments / penalties for network reliability received by SA Power Networks such as those under the AER's STPIS scheme;

- Payments made by SA Power Networks to customers as compensation for loss of supply under ESCOSA's GSL payments scheme;

5.7 Period of study

Study periods may vary from 10 years for relatively minor augmentations such as the upgrade of a substation to 25 years for major strategic decisions such as the provision of new sub-transmission lines. The study period will be advised in the NNOR as part of the description of the identified need.

All options are evaluated over the same period and each option must address each identified constraint that occurs during the period of study; including for instance, constraints that emerge later from increases in forecast demand.

6 Information for Non Network Solution Proponents

6.1 Introduction

SA Power Networks will only accept formal proposals from proponents of non-network solutions in response to a NNOR, which must be in the format specified and received by the closing date specified in the Report. We welcome comments on the Screening Test Notice, Draft Project Assessment Report and DAPR on any aspect of the identified need or proposed solution identified in the document.

Where the proposed solution(s) only partially address the identified need(s), the proposal may be combined with either other proposals or network alternatives to form options that do fully address those needs. SA Power Networks will inform proponents of how this has been performed as part of the evaluation process and when publishing the results.

We do not require any form of pre-registration or prior company validation in order for a party to respond to an identified need specified within the DAPR or RIT-D documents.

SA Power Networks will treat all information as public, unless there is prior agreement to treat the information as commercial-in-confidence. The proponent must be able to demonstrate that the information is commercial-in-confidence. SA Power Networks will publish all relevant information in its Draft and Final Project Assessment Reports on an identified need unless it has agreed to treat certain information as commercial-in-confidence. The publishing of all relevant information will ensure transparency in the evaluation process.

6.2 Information required in proposal

As a minimum, we require sufficient information to be able to evaluate the technical and financial viability of a proposal as well as its ability to be delivered in the required timeframe. SA Power Networks expects this information to include:

- The proponent's contact details;
- Details about the proponent including evidence that demonstrates the ability of the proponent to implement the solution proposed;
- The type, size and location of the technology proposed and a description of how it may fully or partially resolve or delay the system limitation(s).
- The payments to the proponent to be made by SA Power Networks under the proposal. The structure of payments by SA Power Networks to the proponent is outlined in section 7.2.
- An indication of the connection services that the proponent would require – for instance a new connection or connections at a zone substation. SA Power Networks will determine the costs of providing any required connection assets;
- Milestone dates / lead times that would need to be met in order for the proposal to be delivered by the date specified in the NNOR;
- The longevity of the proposal (ie 5 years, 10 years etc).

Examples of third party proposals considered by us in the past include:

- A proposal for a third party embedded generator stating a monthly availability fee and an operational fee based on the cost per MWh of energy generated;
- An indicative offer of the cost of installing dynamic reactive network support to resolve a voltage constraint and to reduce system losses;
- An offer of voluntary load curtailment specifying a monthly availability fee and an operational fee per MWh of load curtailed to a nominated level of demand during the curtailment period.

- Offers to construct assets for adoption by SA Power Networks. Note that we are constrained by our license conditions and the NER ring fencing rules as to what assets we may operate in the NEM.

Examples of proposals that will not be considered are:

- Sales brochures detailing products without pricing or further information particular to the constraint and location;
- An offer for us to pay for consultancy services to investigate an option further;
- An offer that uses unproven technology and requires SA Power Networks to manage the risk of failure;
- An offer for services that are technically unviable – for instance, offers for PV based generation without storage to address a constraint that occurs at 9:00 pm.

If the proponent requires further information in addition to that provided within the published NNOR in order to formulate their proposal, SA Power Networks will generally be willing to provide the requested information provided that:

- The proponent signs an appropriate non-disclosure / confidentiality agreement (eg where the information relates to customer data);
- The disclosure of that information does not breach the Privacy Act or any existing confidentiality or non-disclosure agreements;
- The information requested is deemed by SA Power Networks to be relevant to the proposal;
- The scale of the information requested is reasonable with respect to the potential benefits offered by the proposal.

Where additional information is provided on request to one proponent, SA Power Networks may at its discretion make this publicly available to all potential proponents.

6.3 Non network proposal process

The evaluation and development of non-network proposals fits into our normal planning cycle in the project evaluation and construction phases as described earlier, however certain stages are expanded as explained below to accommodate the commercial realities of involving external parties in resolving network constraints.

6.3.1 Initial RIT-D evaluation

Based on the proposal(s) received, SA Power Networks will evaluate these according to the RIT-D to determine the preferred option. Note: under the NER, we are entitled to combine proposals either in part or their entirety with those received from other proponents or with network proposals in order to maximise the benefits and / or minimise the cost to the electricity market. For instance, this might mean combining a third party proposal for voluntary load curtailment with a small power station owned by someone else.

The results of the initial RIT-D will be formally communicated to all parties who have provided proposals as well as those registered on SA Power Networks' Demand Side Engagement Register.

6.3.2 Concept design development

We will assess the credibility of all proposals using the selection criteria specified in the NNOR. These criteria include financial and technical elements and specify the time frame within which any third party option must be operational. If this initial evaluation indicates that one or more proposals either individually or in combination with other non-network or network solutions are credible options, then SA Power Networks will enter into discussions with the proponent(s) to clarify and further investigate the proposal(s) to produce a concept design. This may require negotiations with multiple parties on a non-exclusive basis.

Particular elements to be considered may include:

- **Location of assets and required network connectivity**

  During these discussions, SA Power Networks will assess (in conjunction with the proponent(s)), how any required connection infrastructure may be optimised including possible line routes / potential sites etc. It is important to recognise however, that the proposal is ultimately at the proponent's risk and that any advice offered by SA Power Networks is on a non-binding / best efforts basis.

- **Assessment and sharing of Risks**

  SA Power Network will assess what it sees are the major risks involved with the proposal including consideration of possible legal, environmental, technical, social and financial risks. SA Power Networks will discuss this assessment with the proponent and attempt to identify measures that may reduce these risks. This assessment may result in SA Power Networks requesting the proponent to carry out additional activities (eg acoustic modelling) as part of this risk assessment process to prove the viability of the proposed option. The proponent will bear the costs of performing any such investigations required to prove the technical viability of an option.

- **Discussion of technical feasibility**

  SA Power Networks will conduct (at its expense) any initial network studies required to confirm the technical feasibility of the proposal in terms of its connection to our network.

  We expect that the proponent will (at its expense) commission any non-electrical studies required such as high level land use, environmental and geotechnical evaluations to confirm to SA Power Networks' satisfaction that the proposal is technically viable.

- **Assessment**

  We will give regular feedback to the proponent(s) through this process on whether or not the pricing of the proposal still forms a credible option in terms of the RIT-D.

We expect that by the end of this stage of the process, SA Power Networks and the proponent(s) will have developed a proposal which all parties have a reasonable expectation of success in terms of the RIT-D and that any refinement of the initial response to the NNOR will have been completed. It is important to note, that the proposal(s) offered by the proponents at this point in time will be assessed as finalised and that SA Power Networks will apply the RIT-D based on this submission.

Note also that this process will be strictly time limited and will be completed by the dates published within the NNOR in order to comply with the AER RIT-D Guidelines.

6.4 Publication of results

The results of the RIT-D evaluation will be formally published in either a Draft Project Assessment Report (DPAR) or a Final Project Assessment Report (FPAR) as required under the NER. Proponents should note that under the NER, these documents are subject to appeal by interested parties and any decision does not become final until the appeal period has ceased and all appeals (if any) are resolved. There are published timeframes within the rules and guidelines specifying the periods within which the publication and appeals must occur.

Any escalation of prices or change in terms from those assessed in response to the NNOR will not be accepted.

6.5 Project Implementation

Where the outcome of the RIT-D indicates that a non-network solution is or forms part of the preferred option, the next step is to progress to detailed design and implementation. SA Power Networks assumes this phase will require close collaboration with the proponent(s) to ensure successful delivery of the project. This process includes but is not limited to the following steps:

- **Finalisation of legal agreements**

  These agreements include a Network System Support Agreement (NSSA) and a Network Connection Agreement (NCA) as applicable. The full list of agreements which may be required are detailed further in section 7.4.

- **Technical studies required to prove feasibility**

  Where embedded generation is proposed to be employed, the required technical studies will vary according to the size and type of technology proposed and may include the performance of both steady state and dynamic studies to assess the impact of the proposal on the network. These studies will be performed in consultation with both the TNSP and AEMO as required.

- **Site / line route options in place**

  Where a proposal requires a new site and / or connection to our network, then property options need to be acquired for the real property / easements to facilitate the connection.

- **Planning and Environmental approvals**

  Any required planning and environmental approvals must be obtained for both SA Power Networks assets (responsibility of SA Power Networks) and third party infrastructure (responsibility of the third party).

It is likely that a deadline date for the successful completion of these activities will be imposed by SA Power Networks to ensure that adequate time remains for the actual construction and commissioning of the preferred option in time to maintain the security of our network.

6.6 Construction and commissioning

SA Power Networks expect this process to be driven by the conditions specified within the signed agreements between the parties which will specify dates, the order of work and inter-dependencies between the parties.

Elements likely to require detailed discussion during this phase are:

- A commissioning plan to ensure that both parties' expectations are met and the final solution is fit for purpose.
- Joint operating protocols detailing how the parties will communicate and interact.
- Procedures for demonstrating that the agreed conditions precedent in the contracts are met by the agreed dates.
- Procedures for demonstrating compliance with the terms of the NSSA and NCA.

7 Provision of Network System Support

7.1 Requirements

In order for SA Power Networks to make payments to third parties for the provision of network system support, the following conditions must be met:

- The proposal must either by itself or in combination with other network or non-network augmentations, reduce, delay or remove a system limitation(s);
- The proposal must be the best economic solution in terms of the RIT-D;
- The third party must enter into a NSSA for the provision of network support which shall detail the payments for the provision of this network support as well as the liabilities of both parties;
- The proposal must gain all necessary approvals such as generation licences, environmental, AEMO and DAC approvals;
- The third party must enter into a NCA with SA Power Networks where required.

7.2 Network System Support payments

We will make payments for the provision of Network System Support Services based on both fixed and variable components. For instance:

- Example 1 – Load Curtailment. Payment of $x per month for agreeing to reduce peak demand by y MW when requested to do so by us and payment of $z per MWh reduction every time we actually request that to occur.
- Example 2 – Embedded Generation. Payment of $x dollars per month for the provision of a y MW power station at a specific point in the network plus $z per MWh when requested by us for each MWh of electricity generated.

SA Power Networks will not enter into offset arrangements where we receive payments from the proponents based on the market value of energy generated. It is SA Power Networks position that the proponent should include these types of revenue streams in its own internal pricing calculations rather than transfer the uncertainty of future prices to SA Power Networks.

7.2.1 Ownership of assets

SA Power Networks cannot operate a power station in the NEM for reasons other than Network System Support purposes. This limits the income streams that can be accessed by SA Power Networks and therefore the economic viability of any design, build and transfer proposal, when compared to ownership and operation of an embedded generator by a third party.

All assets associated with the connection of embedded generation from the point of connection to our network must be constructed and owned by SA Power Networks. Assets from the point of connection to the generation plant shall be the responsibility of the proponent; the cost of which should be included in the proponent’s price offer

7.3 Costs and Risks

7.3.1 Proponent Risk

We expect the proponent of any non-network solution to carry all risks that are within their ability to control, including but not limited to:

- Risks associated with the construction and maintenance of their assets;
- Obtaining and maintaining registration with AEMO (if required);

- Compliance with the terms and conditions imposed by any development approval or environmental licenses;
- Compliance with the terms of the NCA;
- Compliance with the terms of the NSSA and in particular providing the contracted network support as and when requested by SA Power Networks;
- Indemnifying SA Power Networks against any financial losses caused through negligence or failure to operate under the terms of the NSSA and/or NCA. This may include claims against SA Power Networks by customers connected to the distribution network.

7.3.2 Proponent costs

The proponent of a non-network solution will be responsible for all costs incurred in offering the proposed solution from inception to implementation. These costs may include (but are not limited to):

- Proposal development and design;
- Stakeholder engagement (eg planning authorities, environmental bodies);
- Approvals (eg development approval);
- Generator licensing and registration;
- Contract negotiation and legal fees;
- Land and/or easement acquisition;
- Plant procurement and installation;
- Commissioning and testing;

7.3.3 SA Power Networks costs

We will be responsible for the following costs in implementing a non-network solution:

- **Payments to the proposer**

Only those costs and charges as agreed to in the NSSA will be accepted. Note that claims for additional payments outside of the agreement due to circumstances outside of the control of SA Power Networks (eg project overruns, technical difficulties, movements in exchange rates etc.) will not be accepted.

- **Network studies**

SA Power Networks will perform (at its cost) any network studies required to determine the technical feasibility of the proposed solution in terms of its impact on the electricity network. If the evaluation shows that the proposed non-network solution is the preferred option, then we will fund any detailed network studies necessary to confirm the technical aspects of the proposal.

Where the proposal involves embedded generation, the performance of network studies including provision of an Engineering Report required to connect to our network and any dynamic studies required for AEMO registration will be provided by us at our expense. However, the proponent is responsible for providing (at its expense), all required information and modelling of the generator to meet the requirements of SA Power Networks, AEMO and the TNSP (where relevant).

- **Connection costs**

Where a new connection is required, or our distribution system has to be upgraded in order to facilitate the proposed connection of a non-network solution, SA Power Networks will separately fund the costs of construction and commissioning of those connection assets.

7.4 Legal Agreements

SA Power Networks will require the following agreements to be negotiated (as appropriate) with the proponent before committing to any non-network solution.

7.4.1 Network Systems Support Agreement (NSSA)

A NSSA is a contract between SA Power Networks and a non-network solution provider (proponent) that describes the network support services to be provided, and the applicable terms and conditions between the parties in respect to those services. It includes clauses that describe:

- The system support services that the proponent will provide (eg how much generation or load shedding);
- The contract's term;
- The size and frequency of payments that SA Power Networks will make to the proponent;
- The conditions that must be met by both parties before payments will commence;
- The conditions that must be met by the proponent for payments to continue;
- The risks and liabilities that each party will carry as a consequence of the agreement;
- The process for terminating the agreement including the payment of any consequential compensation to either party.

A copy of SA Power Networks' standard NSSA will be provided to any third party who has submitted a credible proposal to the NNOR for the provision of such services.

Note: under the NER, the NSSA contracts between SA Power Networks and any third party are a commercial arrangement and are not regulated by the AER or AEMO.

7.4.2 Network Connection Agreement (NCA)

Any customer connecting to the distribution network must have a connection agreement that describes the terms and conditions of that connection. This is also true of customers signing or participating in a NSSA. The NCA covers:

- The party responsible for different elements of the connection;
- How disagreements over the connection are resolved;
- Technical standards that must be met by both parties;
- Legal responsibilities incurred by the party connecting to our network.

It is important to note, that compliance with the terms and conditions of the NCA is a pre-condition to receiving any payment under a NSSA. However, the cancellation or expiry of a NSSA does not imply the cancellation or expiry of the NCA (ie an embedded generator may remain connected to SA Power Networks' network following the expiry or termination of the NSSA provided that they continue to comply with the terms of the NCA).

7.4.3 Construction Agreement

In parallel to the negotiation of the NSSA and NCA, a Construction Agreement may be negotiated that details the work each party will perform or services that each will provide as part of the construction or commissioning of any works required to facilitate the connection of the third party's installation to the distribution network. This contract will cover:

- Construction and commissioning by SA Power Networks of any connection assets necessary to facilitate connection of the proponent's non-network solution to the network;
- Timing of joint activities.

7.4.4 Joint operating protocols

Following negotiation of a NSSA and NCA, a separate document describing the operational procedures and protocols to be followed by all parties will be negotiated. This document includes elements that describe:

- the operating processes to be used between the proponent and SA Power Networks operators in performing day to day operation (including switching) of the installation;
- Any specific safety considerations to be applied by either party; and
- Operational contact details.

7.4.5 Compliance program

Either as part of the above agreements or separately, SA Power Networks may require the proponent to implement a compliance monitoring program which provides assurance that the proponent remains compliant with the agreed terms and conditions of the agreements (eg generator registration).

7.4.6 Other agreements, contracts and permits

It is a condition of the NSSA and NCA that any ESCOSA or AEMO requirements, such as generator registration are met. In particular, where the NSSA covers the operation of an embedded generator, it is a condition of the contract that registration must be completed (including R2 testing where applicable) prior to the commencement of any network support payments.

It is also our expectation that the proponent will obtain (at their expense and risk) any permits required under planning, environmental or other laws that may be required to enable their proposal to proceed or to continue to operate.

8 Avoided Customer TUOS Payments

8.1 Summary

Avoided TUOS payments are payments made by DNSPs to an embedded generator, or other registered electricity market participant, where that parties activities result in a reduction of the Locational TUOS charges that would otherwise have had to have been paid by the DNSP to the TNSP. These payments are defined within Section 5.4AA, 5.5 and 6 of the NER.

8.2 Legislative Requirements

Under section 5.5 of the NER, SA Power Networks as a DNSP, must make payments to an embedded generator where the operations of that embedded generator change the Locational TUOS payments levied by ElectraNet on SA Power Networks. This section also prescribes how Avoided TUOS payments are to be calculated. In simple terms, the NER states that we must pass through the difference in the Locational TUOS that would have been payable to the TNSP with and without the presence of the embedded generator. Note:

- Locational TUOS is the TUOS component that reflects the transmission costs of supplying an Agreed Maximum Demand at a Transmission Connection Point as specified in section 6A.23.4 (e) of the NER.
- These payments only apply to registered participants; ie to customers registered with AEMO as generators participating in the NEM. They do NOT apply to non-registered generators such as small residential or commercial PV installations.

Section 5.4AA of the NER, requires us to include consideration of any possible avoided TUOS within any system support contract signed with an embedded generator. Therefore, any fees offered by a third party as an option within a RIT-D proposal or levied by an embedded generator within a NSSA shall be deemed to have considered the value of Avoided TUOS and therefore ineligible to receive additional Avoided TUOS payments.

8.3 Application of avoided TUOS in South Australia

In South Australia, the amount paid for Locational TUOS depends on the size of the Agreed Maximum Demand (AMD) at the connection point between the TNSP's and DNSP's networks. The AMD represents the forecast agreed demand, rather than actual peak demand experienced during the year. That is, the Locational TUOS amount paid in a specific year is the same irrespective of the anytime demand. Therefore, in order to reduce the Locational TUOS incurred by SA Power Networks, an embedded generator must be generating at the time of maximum demand or be generating such as to prevent the existing AMD from being exceeded.

SA Power Networks will consider the payment of avoided TUOS payments where an embedded generator warrants that they will generate on at times of peak demand, thereby enabling SA Power Networks to reduce its contracted AMD with the TNSP for a given connection point. It should be noted that:

- Locational TUOS reflects past capital expenditure decisions and a reduction in AMD due to embedded generation which results in excess capacity will have no impact on the Locational TUOS paid at that point.
- The generator must also be aware that it will be liable for any excess demand charges incurred by SA Power Networks should it fail to generate at peak times which results in SA Power Networks exceeding the forecast AMD at the relevant connection point. These charges at the time of publication are \$254 per kW (inclusive of GST) in excess of the AMD (ie exceeding the AMD by 1 MW may incur a penalty of \$254,000).

9 Example of Non Network Option Project

An example of a project involving the use of a non-network option under the former Regulatory Test is a recent (2010) project to alleviate identified constraints at Bordertown Substation. The history of the project is as follows:

Year	Activity
2009	Four constraints were forecast involving Bordertown Substation: • Overloaded substation transformers; • Inability to maintain voltages within required limits at the Bordertown 11kV bus; • Thermal overload of the Keith to Bordertown 33kV sub-transmission line; • Overload of the Keith Connection Point An initial study identified that a non-network option might be a viable alternative to a series of network augmentations.
2010	A Request For Proposals (RFP) (a similar document to a Non-Network Options Report) was issued requesting proposals to resolve the four identified constraints either in part or in full. Three responses were received: • Two for peak lopping diesel generation; and • One for reactive support.
2010	A request for further information was made to those parties who initially responded to the RFP. This included a revised load forecast and our assessment of their initial proposal.
2011	Initial scoping design work commenced to firm up the design, size and cost of the proposed non-network solution, which an initial evaluation according to the Market Benefit limb of the Regulatory Test version 3, suggested was the preferred option. This included commencing negotiations with the proponent for signing of an NSSA and NCA.
2013	The RFP Evaluation Report was published. The power station was commissioned in time for summer 2013/14.

More information can be obtained from the publicly available evaluation report which can be found at:

http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans/final_project_assessment_reports.jsp

10 Compliance Statement

The table below cross references this document with the requirements of Schedule 5.9 of the Rules.

Table 1 Compliance Cross reference

Clause	NER Requirement	Section
a	A description of how the Distribution Network Service Provider will investigate, develop, assess and report on potential non-network options;	4
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;	2 & 6
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;	6.3
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;	6.2
e	An outline of the criteria that will be applied by the Distribution Network Service Provider in evaluating non-network proposals;	5
f	An outline of the principles that the Distribution Network Service Provider considers in developing the payment levels for non-network options;	7.2
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;	7.3
h	The methodology to be used for determining avoided Customer TUOS charges, in accordance with clauses 5.4AA and 5.5; and;	8
i	A summary of the factors the Distribution Network Service Provider takes into account when negotiating connection agreements with Embedded Generators;	3
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;	3
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;	3
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);	9

Clause	NER Requirement	Section
m	A link to any relevant, publicly available information produced by the Distribution Network Service Provider;	1.2
n	A description of how parties may be listed on the demand side engagement register; and	2
o	The Distribution Network Service Provider’s contact details.	1.3