South Australian Energy Transformation

PSCR Supplementary Information Paper

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ElectraNet Corporate Headquarters
52-55 East Terrace, Adelaide, South Australia 5000 • PO Box 7096, Hutt Street Post Office, Adelaide, South Australia 5000
Tel: (08) 8404 7966 • Fax: (08) 8404 7956 • Toll Free: 1800 243 853

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1. Introduction

On 7 November 2016, ElectraNet commenced the South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR).

The purpose of the SAET RIT-T is to identify solutions that will facilitate South Australia's energy transformation and help lower power prices, improve system security and facilitate the transition to lower carbon emissions.

Options that were highlighted in the PSCR include new interconnectors between South Australia and neighbouring eastern states and alternative solutions that do not involve an interconnector, such as demand response, generation options, battery storage and other solutions (a non-interconnector solution).

At a public forum held on 8 December 2016, ElectraNet received feedback from potential proponents of non-interconnector or non-network solutions that more information about both the identified need and ElectraNet's proposed process would assist them to make submissions to the PSCR.

The purpose of this supplementary Information Paper is to provide additional details on:

- the identified need and the likely nature of the services that could meet it;
- aggregate power system targets for service levels from non-network solutions;
- the information that ElectraNet would require from proponents in order to assess their proposed solution options; and
- the process that ElectraNet proposes to adopt to review and assess non-network solutions within the RIT-T.

ElectraNet is committed to finding solutions that are in the best interests of customers.

By publishing this Supplementary Information Paper, ElectraNet is seeking to facilitate potential proponents of non-network solutions to participate in the RIT-T process and propose solutions that could meet the identified need.

In light of publishing this paper, the closing date for feedback and submissions on the PSCR and the associated Market Modelling and Assumptions Report has been extended to 27 February 2017.

2. The identified system security need

2.1 Introduction

ElectraNet has published a PSCR, conducted a public forum, and set out the modelling approach it proposes to use for the RIT-T.[1] As required by the National Electricity Rules (NER), the RIT-T is directed at meeting an identified need[2], which ElectraNet has determined as:

- facilitating greater competition in the wholesale electricity market, to lower dispatch costs and consequently wholesale electricity prices, particularly in South Australia ('market need');
- providing appropriate security of supply, including inertia, frequency response and system strength services in South Australia ('security need'); and
- facilitating the transition to lower carbon emissions and the adoption of new technologies ('emissions need').

This section aims to clarify the security component of the identified need.

The electricity system in South Australia is operated so as to ensure that, following a credible contingency event, the system remains secure and able to withstand another credible contingency.

Non-credible contingency events, such as the loss of the existing Heywood Interconnector between South Australia and Victoria are managed by emergency control schemes to minimise the level of disruption or load shedding that is required in the event they occur.[3] An outage of the Heywood Interconnector, which has historically occurred approximately once every four years, results in 'islanded' operation of the South Australian power system. Such a contingency is referred to as a separation event.

The identified security need is to ensure the necessary resources are available to secure the South Australia power system so far as it is economical to do so, in the event of the non-credible loss of the existing Heywood Interconnector.

2.2 Historical management of a separation event

The Heywood interconnector can both import and export power. Historically it has largely imported power into South Australia.

When a separation event occurs, South Australia immediately loses access to the power that was being imported at the time, creating a shortfall or deficit of supply to meet the instantaneous demand for electricity.[4] This deficit needs to be rapidly reduced and eliminated with the exact speed of action required to maintain secure operation of the power system depending on the operational situation at the time and the size of the

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1 Information available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

2 NER cl 5.16.4(b)(2).

3 The loss of the Heywood Interconnector is classified under the NER as a 'non-credible' contingency.

4 For clarity, this description of the requirements necessary to manage a separation event assume SA is importing power across the Heywood interconnector. If the separation even took place when SA was exporting similar requirements would be necessary to manage high frequencies.

disruption. A major disruption will require clearing the deficit in less than one second to maintain secure operation of the power system within the specified Frequency Operating Standards.[5]

In South Australia, an automatic Under Frequency Load Shedding (UFLS) emergency control scheme acts to clear a shortfall or deficit of supply. UFLS rapidly detects a reduction in the system frequency and disconnects customers to balance supply and demand. UFLS will continue disconnecting customers until the frequency stops falling. This scheme is the major component of "catching" the falling frequency. The inherent physical inertia and governor response characteristics of thermal synchronous generators in South Australia support UFLS in balancing supply and demand and restoring system frequency following a contingency event.

The physical inertia of synchronous generators has supported UFLS by limiting the Rate of Change of Frequency (RoCoF) in South Australia to prevent frequency from falling too fast and allowing UFLS to catch the falling frequency. Historically, South Australia has operated with expected RoCoF of less than 1 Hz/s for the vast majority of the time.[6] UFLS has been an effective emergency response scheme for managing separation events at this RoCoF level. [7]

Generator governor responses have also assisted UFLS to prevent system frequency from falling outside of the Frequency Operating Standards by increasing generator output immediately following a contingency event to minimise the imbalance between supply and demand.

The NER requires 60% of load in South Australia to be capable of automatic disconnection as part of UFLS.

2.3 Requirement for new system security standards

Changes in operating conditions, driven by the rapid emergence and growth in wind and solar renewable generation, falling energy demand – due to restructuring of the economy and improving energy efficiency – and changing relative fuel prices have resulted in the closure and/ or mothballing of thermal generating plant.[8] These changes have substantially reduced the effectiveness of UFLS, and the physical inertia and Frequency Control Ancillary Services (FCAS) available to secure South Australia in the event of a separation from the NEM. As a result, AEMO and the South Australian Government have introduced a number of operational measures to manage emerging security issues in South Australia.

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5 The Frequency Operating Standards in South Australia require system frequency to be managed within the range 47 to 52 Hertz when the South Australian power system is islanded. The standard system frequency in the NEM is 50 Hertz.

6 AEMO, *Future Power System Security Program Progress Report*, 2016

7 With the growth of distributed behind-the-meter PV, the UFLS scheme disconnects generation as well as load. This may exacerbate the low frequency.

8 Playford power station was mothballed in 2012 and closed in 2015. Northern power station closed in 2016. And some gas plant in the state operates under schedules with some periods of mothballing.

2.3.1 Regulating FCAS for credible separation events

Since 2015, AEMO has required 35 MW of regulating FCAS in South Australia whenever a single credible contingency could result in a separation event. This occurs during planned outages of the interconnector where, for example, one circuit is out of service and the unexpected loss of the remaining circuit will lead to an islanded South Australian power grid.

AEMO has procured these services due to the growing risk that there will be insufficient regulating FCAS available in South Australia, within the time frames necessary, to ensure that an islanded system can be operated satisfactorily until interconnection is restored.

2.3.2 Rate of Change of Frequency Standards

The South Australian Government has introduced regulations to ensure that the power system is operated so that, in the event of a non-credible loss of the double circuit Heywood Interconnector, the RoCoF does not exceed 3 Hz/s.

ElectraNet interprets this requirement to be the average RoCoF measured over the first 0.5 seconds. This is considered to be a minimum standard consistent with a stable transition to islanded operation after a separation event. AEMO and the AEMC are currently examining the appropriate RoCoF standard to apply to the NEM. It is possible that the current standard will be replaced by a more onerous standard in the future.

In order to meet the RoCoF requirement, AEMO limits the potential contingency size (i.e. the magnitude of the supply demand imbalance) for a separation event by constraining transfers across the Heywood interconnector to lower levels than would otherwise apply.

This ensures that the RoCoF immediately following a separation event is not excessive, and assists continuity of operation until interconnection is re-established. However, this implementation of the 3 Hz/s RoCoF standard comes at a cost to the market.

In extreme cases, where there could be very few, if any, synchronous generators online, meeting this standard could require the interconnector to be operated at close to zero. Since the introduction of the RoCoF constraint, flows across the Heywood interconnector have been restricted below levels that would otherwise apply for around 17% of the time.

The SAET RIT-T will explore if there are more efficient ways of achieving the 3 Hz/s RoCoF standard and if there is an economic case for limiting RoCoF to lower levels than required by the existing minimum standard to provide enhanced system security.

2.3.3 System strength

System strength is a measure of the resilience of the power system in response to a power system short-circuit fault and is typically quantified using fault levels[9] and short circuit ratios[10].

[9] Fault levels represent the maximum current that can be expected to flow in response to a short-circuit fault at a given voltage level at a given point on the network (units of MVA, or kA)

[10] Defined as the ratio of the Fault MVA/Rated MVA at a given point on the network

Generally, systems with a large proportion of synchronous generation and a small proportion of non-synchronous generation (such as batteries, solar, wind and HVDC interconnection, all of which rely on inverters for grid connection) have greater system strength. This is due to the high inherent fault level contribution from synchronous generation. System strength varies by location within the network, with a key variable being proximity to synchronous generation and other sources with high fault level contribution.

Currently, to meet minimum system strength requirements, AEMO requires that two sufficiently large thermal generating units are synchronised in South Australia at all times. This RIT-T will explore if there are more efficient solutions to these short term arrangements. [11, 12]

ElectraNet will require proponents of non-network solution options to indicate the fault level contribution (or its equivalent) of their proposed equipment. Certain solutions may require additional investment in capability to offset any shortfall in system strength that might emerge from their deployment.

ElectraNet may discuss modifications (including possible changes in location) to proposed non-network solutions if the fault level characteristics of proponent's equipment give rise to system strength concerns, but the non-network solution otherwise appears to be cost-effective and contributes to other technical performance requirements (such as Fast Frequency Response - FFR). These discussions would take place after the initial assessment of feasibility and likely benefit of the non-network solution.

2.4 Evaluation of two system security levels

ElectraNet has identified two levels of system security against which to evaluate potential solutions under this RIT-T, as follows:

- A 'Minimum System Target'; and
- A 'Preferred System Target'.

The minimum target is set to deliver the same level of resilience as the South Australian grid currently has, following the recent introduction of system security measures[13]. The RIT-T will explore if the minimum target can be met more efficiently.

The Preferred System Target is broadly based on historical performance where the South Australian power system was able to withstand islanding following a larger disturbance such as coincident loss of generation and the Heywood Interconnector. In the absence of a system standard defined in the Rules or in other applicable planning standards, this is a reasonable target to explore. The Preferred System Target builds on the Minimum System Target and provides an achievable, higher level of resilience.[14]

11 AEMO, *Secure Operation of South Australia*, 2016

12 Implementation of this requirement ultimately relies on direction to available generators. This arrangement will not prevent the permanent removal of these plant, hence reliance on direction is not a permanent solution.

13 These measures are the 3 Hz/s RoCoF standard introduced by the South Australian Government and AEMO's requirement for two conventional synchronous generators to be operating at all times to provide sufficient system strength.

14 The Preferred System Target can be achieved with additional interconnection. This RIT-T will also explore the capability of non-interconnection solutions to efficiently deliver this level of resilience.

Further details on the Preferred System Target are provided in Section 2.6: Aggregate system targets.

There are multiple reviews of the Rules and the operations of the NEM currently underway, including:

- Various Rule changes undergoing review by the AEMC;
- AEMO's Future Power System Security program; and
- The Independent Review into the Future Security of the National Electricity Market, chaired by Dr Alan Finkel AO.

These have the potential to impact on the minimum or preferred target in a number of ways, such as by introducing new standards or new mechanisms for the procurement of services.

ElectraNet will consider these as far as possible in conducting this RIT-T.

The Minimum System Target and Preferred System Target are intended to provide guidance to non-network proponents on the scale of the solutions that ElectraNet is seeking. The targets are not intended to be interpreted as standards that must be met.

To explore if there are more efficient ways to meet the Minimum System Target, the benefits that can be derived from the following will be evaluated:

- a relaxation of the existing RoCoF constraint on the Heywood Interconnector;
- a relaxation of AEMO's operational requirement to have two conventional generators online at all times; and/or
- a reduced need for regulating FCAS in South Australia during credible separation scenarios.

The magnitude of the benefits derived will be compared to the costs of achieving them to see if there is an economic case to support the solution options, as providing a more efficient outcome.

The incremental benefit of moving from the Minimum System Target to the Preferred System Target is a more resilient system and reduced risk of system black events. This benefit will be quantified and compared to the increment cost to see if the preferred system target is economically efficient. If not, then the Minimum System Target would remain the focus of this RIT-T.

2.5 Selection based on efficiency criteria

A RIT-T is to identify the investment option that 'maximises the present value of net economic benefit to all those who produce, consume and transport electricity' in the market,[15] which typically requires an evaluation of the net market benefits that can be expected to arise with the proposed investment compared to the status quo.

This is sometimes referred to as a market benefit test. A RIT-T can also address a *reliability corrective action*, i.e. to meet a specific service standard linked to network

[15] NER cl 5.16.1 (b).

technical requirements. In such cases, the preferred option may not necessarily deliver a positive market benefit.[16]

Even though one of the identified needs of the current RIT-T is a security need, it has not been framed as a reliability corrective action. That is, neither the Minimum nor Preferred System Targets set out above constitute service standards linked to network technical requirements for the purpose of assessing different options under the RIT-T. Accordingly, the preferred option under this RIT-T must deliver a positive net market benefit under the market benefit test.

For example, there are expected to be quantifiable market benefits from increased wholesale market competition. Removing or reducing the limit on power flows across the Heywood Interconnector by additional interconnection or greater levels of available ancillary services in South Australia should facilitate greater competition (in effect, by increasing the ability for South Australian customers to secure power at lower prices from interstate suppliers).

The market benefit test is explained further in section 5 of this paper.

2.6 Aggregate system targets

Table 1 below sets out the aggregate system targets ElectraNet is seeking to meet in applying this RIT-T. These targets are described qualitatively; i.e. by describing features of the operation of the grid that ElectraNet considers are likely to create benefits to customers and by specifying the quantities of services ElectraNet is seeking.

For each target, there are many different combinations of solutions that could ultimately meet the identified need and the quantities of services required. This table is intended to inform the aggregate likely magnitude of a ‘total’ solution.

[16] A RIT-T in response to a ***reliability corrective action*** can, as a practical matter, be assessed on the basis of the least-cost option for meeting the mandated technical requirement.

		Minimum System Target	Preferred System Target
Description of operating requirements	Normal operation	1. Withstand the loss of the Heywood interconnector with transfers of up to 650 MW without resulting in a system black condition, including effective operation of emergency control schemes 2. Less than or equal to 3 Hz/s RoCoF for a contingency size of up to 650 MW that results in separation from the rest of the NEM – effectively would result in removal of current RoCoF constraint on the Heywood Interconnector. 3. Capability to operate South Australia when connected to the rest of the NEM with no local synchronous generators online.	1. Withstand the loss of the Heywood interconnector with transfers of up to 750 MW without resulting in a system black condition. 2. 1 Hz/s average RoCoF over 500 ms for any contingency size up to 900 MW that results in separation from the rest of the NEM and includes the loss of generation – effectively results in removal of RoCoF constraint on the Heywood Interconnector. 3. 2 Hz/s maximum RoCoF for the first 250 ms.
	Islanded operation	1. Capability to operate islanded for 1 hour in a **satisfactory** manner –any further contingency events could lead to a system black event. 2. Sufficient regulation FCAS in South Australia to manage “small” perturbations in the network for 1 hour. 3. Maintain minimum fault levels across the islanded transmission system.	1. Capability to operate islanded system indefinitely in a **secure** manner. Secure operation restored within 30 minutes from the time of separation 2. Sufficient regulation FCAS in South Australia to manage “small” perturbations indefinitely
Service requirements specification	Inertia	**Inertia**: 4,000 – 4,500 MWs (set by 4 Hz/s back stop to ensure Automatic Access Standard for generators is met[17]) plus sufficient **FFR**	**Inertia**: 9,000 – 9,500 MWs (2 Hz/s back stop) plus sufficient **FFR**

[17] The Rules mandate an Automatic Access Standard for generators that can withstand RoCoF events of 4 Hz/s for 0.25 seconds. ElectraNet considers that this sets an absolute maximum that RoCoF should not exceed for any duration. ElectraNet considers that this must be met by physical inertia, and not a Fast Frequency Response (FFR) that will have a time delay and would therefore result in RoCoF in excess of 4 Hz/s and not satisfy the Automatic Access Standard.

		Minimum System Target	Preferred System Target
	FCAS	Sufficient contingency FCAS or equivalent services[18] to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 650 MW. 35 MW of local regulating frequency (or equivalent) available within 30 minutes and required for no longer than 1 hour following separation.	Sufficient contingency FCAS services to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 900 MW. 35 MW or local regulating frequency available and required continuously. With SA islanded, sufficient raise contingency FCAS services for a 270 MW generator contingency available within 30 minutes of the contingency. With SA islanded, sufficient lower contingency FCAS for a 200 MW load loss event available within 30 minutes of the contingency.
	System strength	2 kA across the system at 275 kV.	4 kA across the system at 275 kV.

Table 1 - Aggregate system security requirements

[18] It is expected a significant proportion of load shedding (UFLS or Special Protection Scheme initiated) will be required in both the Minimum and Preferred target.

The South Australian 3 Hz/s RoCoF standard imposes technical performance requirements on the amount of Fast Frequency Response (FFR) required (MW), the maximum allowable FFR response time, and also the quantity of pre-contingency physical inertia (MW.s) that would allow the interconnector to operate unconstrained by the RoCoF standard up to 650 MW. These requirements are described as follows.

2.6.1 Minimum 3 Hz/s RoCoF standard

Figure 1 describes a system under-frequency response characteristic that satisfies the 3 Hz/s minimum RoCoF requirement. Performance against the 3 Hz/s limit is measured as the average RoCoF over the first 500 ms (green line in figure 3).

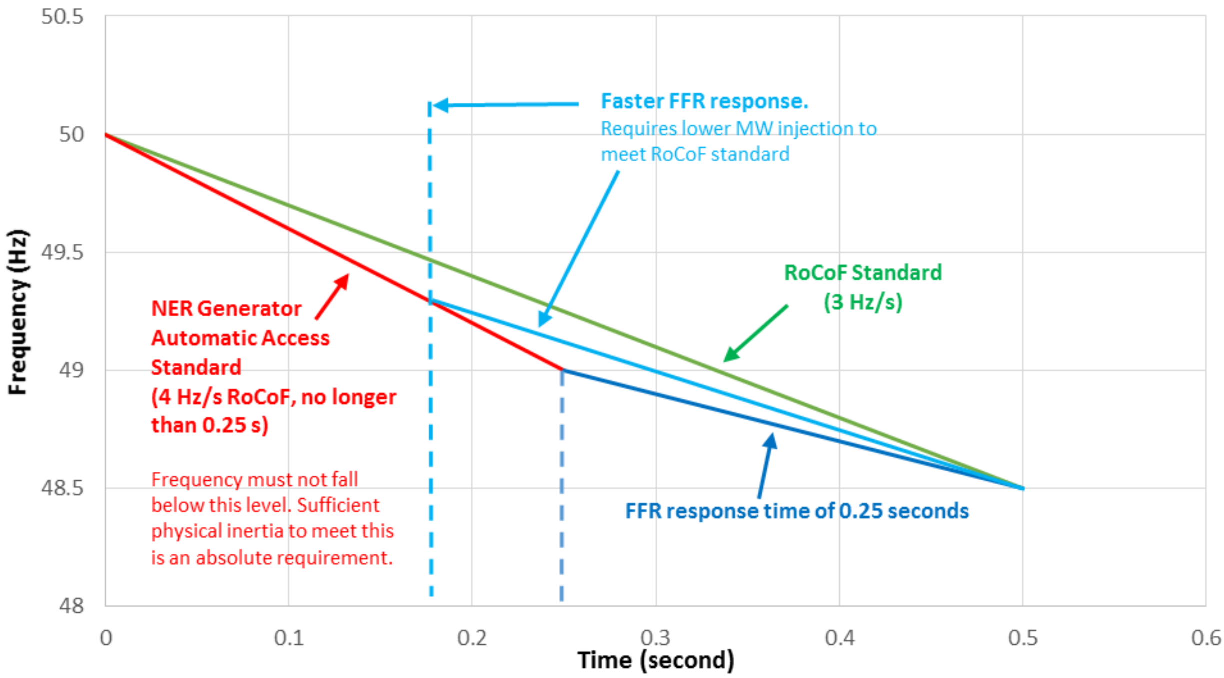

Figure 1 - Alternative Inertia and FFR characteristics to meet minimum 3 Hz/s RoCoF standard

With reference to figure 1.

- A RoCoF of 4 Hz/s (worst allowable case) is allowable for no longer than 250 ms (red line in figure 1).[19] Sufficient inertia to meet this is an absolute requirement and cannot be substituted for by a FFR because of the speed of response required.
- Sufficient FFR power injection with a response time of 250 ms is required to lower the RoCoF over the next 250 ms (dark blue line in figure 1) to meet the 3 Hz/s minimum RoCoF requirement.

[19] This is determined by the Automatic Access Standard (AAS) for existing generation RoCoF fault ride-through/withstand capability. Exceeding this standard would possibly result in all generators disconnecting and creating an even larger supply deficit.

- Application of faster than 250 ms FFR solutions (light blue line in figure 1) would require less power injection than a 250 ms solution to ensure the 3 Hz/s minimum RoCoF requirement.

- Application of slower FFR solutions (i.e. longer total FFR response times) than 250 ms would require additional physical inertia to be operating. This is to ensure that the Automatic Access Standard (AAS) for existing generation RoCoF fault ride-through/ withstand capability is met.

Table 2 below highlights qualitatively how the response time of a FFR solution impacts on the amount of FFR required and/or the minimum inertia level to support the FFR solution.

FFR Total Response Injection Time (ms)	FFR MW Injection & Physical Pre-contingency MW.s Inertia Requirement
>250	Additional physical inertia required to maintain RoCoF < 4 Hz/s[20]
250	300-350 MW FFR injection needed for 650 MW islanding contingency with 4,000-4,500 MW.s of pre-contingency inertia
<250	Faster FFR response will result in reduced FFR MW injection requirements (see Table 2 below)

Table 2 - FFR MW requirements for different response times to meet minimum 3 Hz/s RoCoF requirement

[20] The Automatic Access Standard for generators requires that RoCoF does not exceed 4 Hz/s for 250 ms. If 4 Hz/s exceeds 250 ms, generators may commence disconnecting creating a larger supply deficit. To prevent this, if a FFR response time exceeds 250 ms, additional inertia is required to ensure the RoCoF does not reach 4 Hz/s.

Table 3 below presents some specific examples for quantifying the level of inertia and FFR required to meet the minimum system target based on the FFR response time, which includes full delivery of the FFR response.

	Example 1 – 250 ms response	Example 2 – faster response	Example 3 – slower response	Example 4 - Inertia only
FFR Response Time (ms)	250	150	350	NA
Inertia (MW.s)	4,000 – 4,500	4,000 – 4,500	4,500 – 5,000	5,000 – 5,500
Inertia increase from example 1 (MW.s)		0	500 – 1,000	1,000, 1,500
FFR Required (MW)	300-350	200-250	250-300	0
FFR reduction from example 1 (MW)		~100	~50	300-250

Table 3 – Trade-off between FFR MW and system inertia requirements for different FFR response times to meet minimum 3 Hz/s RoCoF requirement

2.6.2 Preferred 1 Hz/s RoCoF target

The preferred 1 Hz/s RoCoF target is to be assessed over the first 500 ms. To meet this target with a combination of inertia and FFR, RoCoF would need to be kept below around 2 Hz/s in the first 250 ms, although unlike for the 3 Hz/s target, there is no absolute value to stay above. [21]

Meeting this preferred target would require more inertia and FFR capability than the 3 Hz/s RoCoF standard.

[21] The AAS remains an absolute maximum, however, if this level is reached it is not possible to meet the preferred target of 1 Hz/s.

Table 4 below highlights how the response time of a FFR solution impacts on the amount of FFR required as well as the minimum inertia level to support the FFR solution.

FFR Total Response/Injection Time (ms)	FFR MW Injection & Physical Pre-contingency MW.s Inertia Requirement
>250	Additional physical inertia required to maintain RoCoF < 2 Hz/s
250	475-525 MW FFR injection needed for 750 MW islanding contingency with 9,-000-9,500 MW.s of pre-contingency inertia
<250	Faster FFR response will result in reduced FFR MW injection requirements (see Table 4 below)

Table 4 - FFR MW requirements for different response times to meet preferred 1 Hz/s RoCoF target

Table 5 below presents some specific examples for quantifying the level of inertia and FFR required to meet the preferred target.

	Example 1 – 250 ms response	Example 2 – faster response	Example 3 – slower response	Example 4 – inertia only
FFR Response Time (ms)	250	150	350	NA
Inertia (MW.s)	9,000 – 9,500	9,000 – 9,500	11,500 – 12,000	18,500 – 19,000
Inertia increase from scenario 1 (MW.s)		0	▲650 - 700	▲1,300 – 1,400
FFR Required (MW)	475 - 525	425-475	425-475	0
FFR reduction from scenario 1 (MW)		▼50	▼50	▼475-525

Table 5 – Trade-off between FFR MW and system inertia requirements for different FFR response times to meet preferred 1 Hz/s RoCoF target

3. Non-network proponent submissions

3.1 General information for proponents

ElectraNet strongly encourages proponents of non-network solution options to address all of the information requirements specified below that are relevant to their proposal, so as not to compromise the extent to which their proposal can be considered in the process.

Proponents should also note the following:

- projects should provide the timeframes required for the project to be completed and in operation, as well as the expected operating life
  - benefits will be recognised from the date of implementation, to the extent that they contribute to the identified need
  - ElectraNet will give consideration to using non-network projects as shorter term interim solutions to meet the identified needs as part of an overall solution
  - proponents should indicate if the provision of the identified services is expected to change over the expected operating life, e.g. gradual performance degradation over the lifecycle of the asset such as battery storage capacity
- projects must be of a minimum size in at least one service category as defined in Table 6 to be considered under this RIT-T.
  - ElectraNet will consider proposals that rely on aggregation of services from multiple sites or equipment (e.g. many distribution network-connected/ “behind the meter” batteries aggregated into a single large “virtual” battery), subject to the necessary monitoring, control, response speed/ time, reliability and related considerations being met
  - where the minimum size of a service category is not met, that solution will not be considered as providing that service category.
- the proponent must:
  - identify the services it is proposing to provide according to the service categories summarised in Table 6
  - identify the location or locations of the equipment providing the services
  - if offering more than one service from a single non-network solution and there is a dependency between them or mutual exclusion (e.g. a storage limit on battery technology), then this must be identified.

3.2 Commercial information requirements

Proponents should be prepared to provide the following commercial information in response to the PSCR and this Information Paper:

- the expected capital cost of the facilities at the time of commissioning (but not including the costs of connection assets, which will be estimated by ElectraNet);
- as appropriate, the fixed operating and maintenance costs of providing the relevant services, and any variable costs (or usage payments) if the service is called upon;
- the duration of service availability: proponents should provide costs for three-year contract, a ten-year contract and a preferred duration;
- the offer price of the service — given the nature of the services and identified security need, ElectraNet would expect prices to take the form of a capacity or availability payment (e.g. expressed in terms of $/year per unit of capacity or capability that is offered such as $1,000 per annum per MW.s of inertia);
- appropriate material evidencing:
  - the robustness and performance of the underlying technology; and
  - the financial and technical capabilities of the proponent.

Indicative commitments would be sufficient for responses to the Project Specification Consultation Report and this Supplementary Information Paper.

However, if ElectraNet determines that a non-network solution could meet the identified need and is to be considered further in the RIT-T economic assessment, it will require binding commitments from selected proponents before finalisation of the Project Assessment Draft Report, around mid-year 2017.

The subsequent binding commitments would be expected to include the following, in addition to standard procurement clauses:

- a commitment to price;
- an agreed timetable for implementation;
- measures aimed at ensuring reliability, availability, monitoring and control of the requisite services. Monitoring and control requirements are likely to be broadly consistent with approaches adopted by AEMO[22];
- incentive arrangements to help ensure reliability and availability; and
- an indemnity in favour of ElectraNet against any liability arising directly or indirectly from the operation or failure of the non-network solution.

[22] AEMO, *Final Determination – Standard for power system data communications*, 2005

3.3 Specific technical information required

Proponents should complete the following information requirements relevant to their solution option, i.e. the minimum requirements only apply for the specific service addressed.

Aspect	Information Required	Unit	Minimum Requirement (standalone Non-Network solutions)
Inertia	Physical Inertia	MWs	500 MWs
Fast Frequency Response (Synthetic Inertia)	Detection time (Local Measurements)	ms	
	Processing time (Based on from receipt of remote signals)	ms	
	Response time (from 0 to maximum capacity)	ms	within 500 ms
	Total Power Injection/Demand Response	MW	50 MW
Regulation FCAS, raise and lower.	Capability	Yes/No	As per FCAS market arrangements[23]
	If Yes, describe capability		10 MW
Contingent FCAS (6s, 60s 5min), raise and lower	Capability	Yes/No	As per FCAS market arrangements
	If Yes, describe capability		10 MW
System Strength	Fault Contribution for a fault at the transmission connection point	kA	0.1 kA @ 275 kV
	Minimum Short Circuit Ratio (SCR) required for stable operation		Note – A number of locations in SA have SCR < 2.0

23 AEMO, *Market ancillary service specification*, 2012

Aspect	Information Required	Unit	Minimum Requirement (standalone Non-Network solutions)
Fault ride through (including response to frequency and voltage disturbances)	Meets at least minimum NER and ESCOSA performance requirements	Yes/No	
	Response Characteristics (if available)		
Capital Cost		$m	
O&M Costs		$/year	
Cost of service (all inclusive)	Fixed and Variable Charges (as applicable)	$/year	
Duration of service offered		Years	
Cost of service for a 3 year contract (all inclusive)	Fixed and Variable Charges (as applicable)	$/year	
Availability and Reliability	Availability	% of year	> 99%
Project references of similar size			
PSS/E Models (if applicable)	As per NER connection guidelines	Yes/No	
Additional Information			
Overload capability	% of name-plate capacity		
Operating Modes			
Reactive capabilities		MVar	

Aspect	Information Required	Unit	Minimum Requirement (standalone Non-Network solutions)
Special Control Features			
Cold and Warm Starts (if applicable)		Hours	
Design Life		Years	
Charge / discharge efficiency	30% will be assumed if not provided.		
Total anticipated installed storage	Detail if additional storage is available over and above any requirements to meet security needs. Zero will be assumed if not provided.	MWh	

Table 6 - Technical information template

4. Evaluation of non-network solutions

4.1 Stand-alone non-network solutions

4.1.1 Meeting the Minimum System Requirement

ElectraNet's primary evaluation approach in respect of stand-alone non-network solutions options (i.e. without an interconnector) will be to assess whether they can feasibly meet the Minimum System Requirement as part of an integrated solution at a cost that is less than the cost imposed by the current arrangements for meeting this requirement. The current cost includes:

- the extra costs of running gas fired generation in South Australia when, absent the security consideration, lower cost renewable sources could meet demand;
- restrictions on the availability of lower cost generation from interstate sources resulting from limitations imposed on power flows across the Heywood Interconnector; and
- higher costs of market ancillary services in South Australia due to limitations on the availability of ancillary services from interstate sources.

ElectraNet cannot predict the likely quantum of non-network solutions that may be proposed in response to this RIT-T. It is possible that the quantum will be sufficient to meet the minimum 3 Hz/s standard at sustained transfers across the Heywood Interconnector in excess of 650 MW, but not sufficient to meet the Preferred System Target. Should this be the case, ElectraNet would still evaluate the incremental market benefits of exceeding the Minimum System Target and whether these are material.

The costs of meeting the Minimum System Target would reflect the offer price that proponents submit. Some non-network solution providers will be able to secure market revenues (from energy and market ancillary services) while also providing regulated services under this RIT-T. This is not a consideration for the RIT-T process, which will consider only the proponent's offer price for the proposed non-network solution option in the assessment of any non-network solution.

4.1.2 Meeting the Preferred System Target

The same broad approach will be used to evaluate any option capable of delivering the Preferred System Target, namely:

- evaluate the market benefit of reduced likelihood of supply interruptions represented by the estimated reduced cost of supply interruptions to the community; and
- evaluate the market benefits that arise from lower market operating costs facilitated by increased trade and higher sustained power transfers across the Heywood Interconnector.

If there is an economic case for a non-network solution option to provide services to meet the Preferred System Target, then the costs and benefits of this option will be compared with alternative options, including additional interconnection and other non-network solutions.

4.2 Combined solutions

It is possible that a combination of network and non-network solutions may provide an optimal means of meeting the identified need. It is also possible that different combinations of non-network solutions may be capable of meeting the identified need in the absence of additional interconnection.

4.2.1 Solutions that meet many of the criteria

In assessing a solution based solely on non-network options, ElectraNet would select the bundle of offered non-network services most likely to meet the identified need with greatest net market benefit. The final selection of the preferred bundle would be made in response to binding commitments from proponents following the initial assessment phase.

4.2.2 Consideration of both interconnector and non-interconnector solutions

If a stand-alone non-interconnector solution is not technically or economically feasible, ElectraNet will nevertheless still examine whether acquisition of non-network solution services could enhance the market or security benefits that arise under any interconnector options.

These benefits could result from improving the utilisation of new or existing network infrastructure or reducing the risk or scale of a future major customer disruption beyond the resilience provided by the addition of another interconnector.

5. Process

The general process that will be followed in conducting the RIT-T is set out in the material that ElectraNet has already published.[24] The following additional information may be helpful to proponents of non-network solution options.

5.1 Initial assessment of feasibility and likely benefit

ElectraNet proposes to make an initial assessment of whether the minimum 3 Hz/s and preferred 1 Hz/s RoCoF standards can be met by means of some or all of the proposed non-network solutions in the absence of a new interconnector having regard to the likely technical envelope of the islanded South Australian system and the performance characteristics of the proposed non-network solutions.

The technical information that ElectraNet will require from proponents to make this assessment is set out in section 4.

If the minimum standard can be met more efficiently by proposed non-network solutions than by current arrangements (i.e. by limiting Heywood Interconnector transfer capability and requiring a minimum number of thermal generators synchronised within South Australia), then ElectraNet will embark upon a detailed assessment of these solutions.

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[24] Available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

If not, ElectraNet will not undertake any further review of non-network options as a stand-alone solution (i.e. without a new interconnector). As noted in section 4.2.2 above, non-network solutions may nevertheless contribute to or change the net costs and benefits of new interconnector options.

The initial screening of non-network solution options will be undertaken within Phase 1 of the market modelling as set out in the RIT-T: Market Modelling Approach and Assumptions Report published on 21 December 2016.

5.1.1 Implementation and expected performance of the non-network solution

ElectraNet must be satisfied that:

- the proposed non-network solution is technologically proven;
- the proponent has the necessary financial and technical capabilities to develop the non-network solution in a timely fashion;
- the timetable for implementation of the non-network solution is consistent with the timetable over which network solutions could meet the identified need; and
- additional requirements such as land availability and permitting are feasible within the development timetable.

ElectraNet will expect proponents to provide information to demonstrate that their proposals meet these requirements. ElectraNet may undertake due diligence to obtain a required level of assurance regarding the information provided.

5.2 Binding commitment

If ElectraNet determines that a non-network solution is likely to be the preferred option under the RIT-T, it will issue a tender for binding commitments before completing the Project Assessment Draft Report. The binding commitment would be expected to include, in addition to standard procurement clauses:

- a commitment to price;
- an agreed timetable for implementation;
- measures aimed at ensuring reliability, availability, monitoring and control of the requisite services, likely to be broadly consistent with approaches adopted by the AEMO;
- incentive arrangements to help ensure reliability and availability;
- transitional arrangements should AEMO implement ancillary services markets for some or all of the services; and
- an indemnity in favour of ElectraNet against any liability arising directly or indirectly from the operation or failure of the non-network solution.

5.3 Engagement with proponents

In light of publishing this Supplementary Information Paper, the closing date for feedback and submissions on the PSCR published on 7 November 2016, and the associated Market Modelling and Assumptions Report published on 21 December 2016, has been extended to 27 February 2017.

ElectraNet expects to engage with proponents during both the initial and subsequent detailed assessment phases of the RIT-T on matters such as service location, connection requirements, monitoring and control strategies, special protection schemes, performance standards and expected commercial contract terms and conditions.

ElectraNet welcomes enquiries from proponents in relation to this Supplementary Information Paper.